Primo Water Corp
Form 8-K
November 12, 2013

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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 12, 2013

PRIMO WATER CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	001-34850	30-0278688
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

104 Cambridge Plaza Drive
Winston-Salem, NC 27104
(Address of Principal Executive Offices)(Zip Code)

Registrant's telephone number, including area code: 336-331-4000

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

¨Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

¨Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

¨Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

¨Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02 Results of Operations and Financial Condition.

On November 12, 2013, Primo Water Corporation (the "Company") issued a press release announcing its financial results for the quarter ended September 30, 2013. A copy of the press release is being furnished as Exhibit 99.1 to this Current Report on Form 8-K.

The information in this Current Report on Form 8-K and Exhibit 99.1 attached hereto is intended to be furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 (the "Exchange Act") or otherwise subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933 or the Exchange Act, except as expressly set forth by specific reference in such filing.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

The following exhibit is furnished herewith:

Exhibit No.	Exhibit Description
99.1	Press Release, dated November 12, 2013.

Signature

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 hereunto duly authorized.

	PRIMO WATER CORPORATION	
Date: November 12, 2013	By:	/s/ Mark Castaneda
	Name:	Mark Castaneda
	Title:	Chief Financial Officer and Secretary

SECURITIES AND EXCHANGE COMMISSION
Washington, DC

EXHIBITS

CURRENT REPORT
ON
FORM 8-K

Date of Event Reported:	Commission File No:
November 12, 2013	001-34850

PRIMO WATER CORPORATION

EXHIBIT INDEX

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Cash and cash equivalents	$ 270,001	$ 270,673
Accounts receivable — Trade, net of allowance for uncollectible accounts of $419 and $5,172, respectively	175,240	145,519
Unbilled revenue	17,308	17,854
Costs in excess of billing	11,829	9,305

Other current assets	120,670	122,209
Total current assets	595,048	565,560
Property and equipment	4,454,976	4,352,109
Less — accumulated depreciation	(1,789,416)	(1,488,403)
	2,665,560	2,863,706
Other assets:		
Equity investments	187,694	189,411
Goodwill	76,134	78,643
Other assets, net	82,137	82,213

	$ 3,606,573	$ 3,779,533
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 163,975	$ 155,457
Accrued liabilities	202,154	200,607
Current maturities of long-term debt	11,396	12,424
Total current liabilities	377,525	368,488
Long-term debt	1,347,994	1,348,315
Deferred income taxes	383,652	442,607
Asset retirement obligations	165,799	

		182,399
Other long-term liabilities	5,109	4,262
Total liabilities	2,280,079	2,346,071
Convertible preferred stock	1,000	6,000
Commitments and contingencies		
Shareholders’ equity:		
Common stock, no par, 240,000 shares authorized, 105,681and 104,281 shares issued, respectively	906,153	907,691
Retained earnings	416,365	519,807
Accumulated other comprehensive loss	(20,502)	(22,241)
Total controlling interest shareholders’ equity	1,302,016	1,405,257
Noncontrolling interests		

		23,478
		22,205
Total equity		
		1,325,494
		1,427,462
	$	3,606,573
	$	3,779,533

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

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Net revenues:		
Contracting services	$ 196,676	$ 404,647
Oil and gas	102,586	89,992
	299,262	494,639
Cost of sales:		
Contracting services	140,126	312,502
Oil and gas	94,092	(16,692)
Oil and gas property impairments	159,862	63,073
	394,080	358,883
Gross profit (loss)	(94,818)	135,756
Gain on oil and gas derivative contracts	2,482	4,121
Gain (loss) on sale or acquisition of assets, net	(14)	1,319
Selling and administrative expenses	(24,546)	(39,372)
Income (loss) from operations	(116,896)	101,824
Equity in earnings of investments	1,656	6,264
Gain on sale of Cal Dive common stock	—	59,442
Net interest expense	(20,523)	(15,644)
Other income (expense)	(1,659)	8,176
Income (loss) before income taxes	(137,422)	160,062
Provision (benefit) for income taxes	(52,366)	56,809
Income (loss) from continuing operations	(85,056)	103,253
Discontinued operations, net of tax	(17)	9,836
Net income (loss), including noncontrolling interests	(85,073)	113,089
Less: net income applicable to noncontrolling interests….	(444)	(12,620)
Net income (loss) applicable to Helix	(85,517)	100,469
Preferred stock dividends	(34)	(250)
Net income (loss) applicable to Helix common shareholders	$ (85,551)	$ 100,219
Basic earnings (loss) per share of common stock:		
Continuing operations	$ (0.82)	$ 0.92
Discontinued operations	—	0.10
Net income (loss) per common share	$ (0.82)	$ 1.02
Diluted earnings (loss) per share of common stock:		
Continuing operations	$ (0.82)	$ 0.85
Discontinued operations	—	0.09
Net income (loss) per common share	$ (0.82)	$ 0.94

Weighted average common shares outstanding:		
Basic	104,125	96,936
Diluted	104,125	105,995

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)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net revenues:		
Contracting services	$ 307,531	$ 815,441
Oil and gas	193,301	250,173
	500,832	1,065,614
Cost of sales:		
Contracting services	226,374	638,200
Oil and gas	172,446	67,375
Oil and gas property impairments	170,974	63,073
	569,794	768,648
Gross profit (loss)	(68,962)	296,966
Gain on oil and gas derivative contracts	2,482	78,730
Gain on sale or acquisition of assets, net	6,233	1,773
Selling and administrative expenses	(65,047)	(80,725)
Income (loss) from operations	(125,294)	296,744
Equity in earnings of investments	6,711	13,767
Gain on sale of Cal Dive common stock	—	59,442
Net interest expense	(36,158)	(37,611)
Other income (expense)	(7,217)	7,948
Income (loss) before income taxes	(161,958)	340,290
Provision (benefit) for income taxes	(59,927)	121,728
Income (loss) from continuing operations	(102,031)	218,562
Discontinued operations, net of tax	(44)	7,282
Net income (loss), including noncontrolling interests	(102,075)	225,844
Less: net income applicable to noncontrolling interests…	(1,273)	(18,173)
Net income (loss) applicable to Helix	(103,348)	207,671
Preferred stock dividends	(94)	(563)
Preferred stock beneficial conversion charges	—	(53,439)
Net income (loss) applicable to Helix common shareholders	$ (103,442)	$ 153,669
Basic earnings (loss) per share of common stock:		
Continuing operations	$ (1.00)	$ 1.50
Discontinued operations	—	0.08
Net income (loss) per common share	$ (1.00)	$ 1.58
Diluted earnings (loss) per share of common stock:		
Continuing operations	$ (1.00)	$ 1.37
Discontinued operations	—	0.07

Net income (loss) per common share	$ (1.00)	$ 1.44
Weighted average common shares outstanding:		
Basic	103,610	96,077
Diluted	103,610	106,000

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)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash flows from operating activities:		
Net income (loss), including noncontrolling interests	$ (102,075)	$ 225,844
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by operating activities		
Depreciation and amortization	146,268	157,289
Asset impairment charge and dry hole expense	170,784	63,499
Equity in earnings of investments, net of distributions	—	(3,697)
Amortization of deferred financing costs	3,768	2,903
Loss (income) from discontinued operations	44	(7,282)
Stock compensation expense	4,589	7,188
Amortization of debt discount	4,136	3,876
Deferred income taxes	(54,749)	19,917
Excess tax benefit from stock-based compensation	2,163	754
Gain on sale or acquisition of assets	(6,233)	(1,773)
Unrealized (gain) loss on derivative contracts	2,813	(24,667)
Gain on sale of investment in Cal Dive common stock	—	(59,442)
Changes in operating assets and liabilities:		
Accounts receivable, net	(30,591)	(14,231)
Other current assets	16,477	15,704
Income tax payable	(10,811)	124,531
Accounts payable and accrued liabilities	28,027	9,220
Asset retirement obligation costs	(28,727)	(11,775)
Other noncurrent, net	(9,439)	(78,865)
Cash provided by operating activities	136,444	428,993
Cash used in discontinued operations	(44)	(6,121)
Net cash provided by operating activities	136,400	422,872
Cash flows from investing activities:		
Capital expenditures	(135,612)	(238,402)
Investments in equity investments	(6,307)	(454)
Distributions from equity investments, net	8,132	3,253
Insurance recovery for capital items	16,106	—
Proceeds from sale of Cal Dive common stock	—	196,656
Reduction in cash from deconsolidation of Cal Dive	—	(112,995)
Proceeds from sales of property	—	23,238

Other	109	(15)
Net cash used in investing activities	(117,572)	(128,719)
Cash provided by discontinued operations	—	20,874
Net cash used in investing activities	(117,572)	(107,845)

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

	Six Months Ended June 30,	
	2010	2009
Cash flows from financing activities:		
Repayment of Helix Term Loan	(2,163)	(2,163)
Repayments on Helix Revolver	—	(349,500)
Repayment of MARAD borrowings	(2,403)	(2,081)
Borrowings on CDI Revolver	—	100,000
Repayments on CDI Term Note	—	(20,000)
Deferred financing costs	(2,792)	(28)
Repurchases of common stock	(9,127)	(753)
Excess tax benefit from stock-based compensation	(2,163)	(754)
Loan note repayment, preferred stock dividends paid and other	(1,098)	(500)
Net cash used in financing activities	(19,746)	(275,779)
Effect of exchange rate changes on cash and cash equivalents	246	(931)
Net (decrease) increase in cash and cash equivalents	(672)	38,317
Cash and cash equivalents:		
Balance, beginning of year	270,673	223,613
Balance, end of period	$ 270,001	$ 261,930

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

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

Note 1 – Basis of Presentation

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. and its majority-owned subsidiaries (collectively, "Helix" or the "Company"). Unless the context indicates otherwise, the terms "we," "us" and "our" in this report refer collectively to Helix and its majority-owned subsidiaries. Until June 2009, Cal Dive International, Inc. (collectively with its subsidiaries referred to as “Cal Dive” or “CDI”) was a majority-owned subsidiary of Helix. Helix sold substantially all its ownership interest in Cal Dive during 2009 (see Note 4 below and Note 3 of our Annual Report on Form 10-K for the year ended December 31, 2009 (“2009 Form 10-K”)). All material intercompany accounts and transactions have been eliminated. These unaudited condensed consolidated financial statements have been prepared pursuant to instructions for the Quarterly Report on Form 10-Q required to be filed with the Securities and Exchange Commission (“SEC”), and do not include all information and footnotes normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles.

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles and are consistent in all material respects with those applied in our 2009 Form 10-K. The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and the related disclosures. Actual results may differ from our estimates. Management has reflected all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes are necessary for a fair presentation of the condensed consolidated balance sheets, results of operations, and cash flows, as applicable. The operating results for the periods ended June 30, 2010 are not necessarily indicative of the results that may be expected for the year ending December 31, 2010. Our balance sheet as of December 31, 2009 included herein has been derived from the audited balance sheet as of December 31, 2009 included in our 2009 Form 10-K. These unaudited condensed consolidated financial statements should be read in conjunction with the annual audited consolidated financial statements and notes thereto included in our 2009 Form 10-K.

Certain reclassifications were made to previously reported amounts in the condensed consolidated financial statements and notes thereto to make them consistent with the current presentation format.

Note 2 – Company Overview

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

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

Services business primarily consists of deepwater construction and well operation activities. Formerly, we had a third Contracting Services segment, Shelf Contracting, which represented the assets of CDI. We sold substantially all of our ownership of CDI through various transactions in 2009 (Note 4). Our Production Facilities business includes our investments in Deepwater Gateway, L.L.C. ("Deepwater Gateway"), Independence Hub, LLC ("Independence Hub") and the Helix Producer I ("HP I") vessel.

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Oil and Gas Operations

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

Discontinued Operations

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

Business Strategy

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

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

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

Recent Events in Gulf of Mexico

Oil Spill

On April 20, 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252. The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill, the magnitude of which is unprecedented in U.S territorial waters. The operator of the Macondo project, BP PLC ("BP") has recently controlled the flow of the oil from the well and ultimately plans to plug the well. Simultaneously, efforts to contain and ultimately remediate the environmental impacts caused by the oil spill are ongoing. We have contracted three of our vessels, the Q4000, the Express and the HP I to participate in the coordinated containment response to the oil spill in the Gulf of Mexico.

Drilling Moratorium

On May 12, 2010, the U.S. Department of Interior ("DOI") announced a total moratorium on new drilling in the Gulf of Mexico. This moratorium also affected 33 in progress wells in the deepwater. On May 28, 2010 the moratorium on drilling in the shallow water of the Gulf, as defined as water depths less than 500 feet, was lifted. However, the DOI extended the drilling moratorium on deepwater wells through November 2010. This drilling moratorium was challenged in court and the court enjoined its enforcement. However, the DOI has recently amended its drilling moratorium which remains in effect at the time of this filing despite additional potential legal challenges.

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Note 3 – Details of Certain Accounts

Other current assets consisted of the following as of June 30, 2010 and December 31, 2009:

	June 30, 2010	December 31, 2009
	(in thousands)	
Other receivables	$ 3,851	$ 7,990
Prepaid insurance	12,901	11,105
Other prepaids	16,545	21,819
Inventory	25,808	25,755
Current deferred tax assets	15,057	24,517
Hedging assets	15,306	6,214
Gas imbalance	6,774	7,655
Income tax receivable	18,139	8,492
Assets of discontinued operations	825	878
Other	5,464	7,784
	$ 120,670	$ 122,209

Other assets, net, consisted of the following as of June 30, 2010 and December 31, 2009:

	June 30, 2010	December 31, 2009
	(in thousands)	
Restricted cash	$ 35,519	$ 35,409
Deferred drydock expenses, net	14,238	12,030
Deferred financing costs	29,284	30,061
Intangible assets with finite lives, net	713	768
Other	2,383	3,945
	$ 82,137	$ 82,213

Accrued liabilities consisted of the following as of June 30, 2010 and December 31, 2009:

	June 30, 2010	December 31, 2009
	(in thousands)	
Accrued payroll and related benefits	$ 25,976	$ 30,513
Royalties payable	11,146	5,717
Asset retirement obligation	76,708	65,729
Unearned revenue	9,188	3,672
Accrued interest	27,826	27,830
Billing in excess of cost	6,814	—
Deposit	25,542	25,542
Hedge liability	5,108	19,536

Liabilities of discontinued operations	13	451
Other	13,833	21,617
	$ 202,154	$ 200,607

Note 4 — Ownership of Cal Dive International, Inc.

In January 2009, we sold approximately 13.6 million shares of Cal Dive common stock to Cal Dive for $86 million. This transaction constituted a single transaction and was not part of any planned set of transactions that would have resulted 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.

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

We continue to own 0.5 million shares of Cal Dive common stock, representing less than 1% of the total outstanding shares of Cal Dive. Accordingly, we now classify our remaining interest in Cal Dive as an investment available for sale pursuant to ASC Topic No. 320 "Investment - Debt and Equity Securities." As an investment available for sale, the value of our remaining interest will be marked-to-market at each period end with the corresponding change in value being reported as a component of other accumulated comprehensive income (loss) in the accompanying condensed consolidated balance sheets (Note 11). The pre-tax value of our remaining investment in Cal Dive as of June 30, 2010 has decreased $0.9 million since December 31, 2009 and $2.2 million since our Cal Dive sales transaction in September 2009. We consider our unrealized losses on our remaining Cal Dive investment to be temporary. We will continue to monitor our investment and should we determine that these losses are not temporary we will remove the unrealized amounts from our accumulated comprehensive loss by recording the difference between our original investment and the then expected realizable value as a non operating expense charge in our consolidated statement of operations.

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

Note 5 – Convertible Preferred Stock

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

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

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

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In May 2010, Fletcher converted $5 million of its Series A-1 Cumulative Convertible Preferred Stock into 1,807,011 shares of our common stock. In the third quarter of 2009, Fletcher converted $19 million of its Series A-1 Cumulative Convertible Preferred Stock into 6,866,641 shares of our common stock. The remaining $1 million of the Series A-1 Cumulative Convertible Preferred Stock, which is convertible into 361,402 shares of our common stock, maintains its mezzanine presentation below liabilities but is not included as a component of shareholders' equity, because we may, under certain instances be required to settle any future conversions in cash. Prior to any future conversion(s), the common shares issuable will be assessed for inclusion in our diluted earnings per share computations using the if converted method based on the applicable conversion price of $2.767 per share, meaning that for all periods in which we have positive earnings from continuing operations and our average stock price exceeds $2.767 per share we will have an assumed conversion of convertible preferred stock and the 361,402 shares will be included in our diluted shares outstanding amount.

Note 6 – Oil and Gas Properties

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

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

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

Mid Year Reserve Assessment

In connection with our regular mid-year review as well as our efforts to pursue potential divestment alternatives for our oil and gas business, we engaged an independent petroleum reservoir engineering firm to update our estimates of proved reserves for our domestic oil and gas properties as of June 30, 2010. The resulting independent petroleum engineer reserve report indicated the we had a significant reduction in proved reserves resulting from a combination of factors including well performance issues at certain of our producing fields, most notably our Bushwood field at Garden Banks Blocks 462/463/506/507, as well as changes in the field economics of some of our other oil and gas properties. The changes in field economics primarily affected properties that were either close to the end of their production life or in which we had proved undeveloped reserves, which would have been required to be developed in the near term. The decision not to develop these properties in light of these economic changes was also driven by our desire to pursue potential alternatives to divest our oil and gas business and the increasing uncertainties about future oil and gas operations in the Gulf of Mexico as a result of the oil spill from the Macondo well. As a result of the reduction in estimated reserves we were required to record oil and gas property impairment charges of $159.9 million at June 30, 2010.

Impairments

Following the determination of a significant reduction in our estimates of proved reserves at June 30, 2010, we recorded oil and gas property impairment charges totaling $159.9 million which affected the carrying value of 15 of our Gulf of Mexico oil and gas properties.

In the first quarter of 2010, we recorded $7.0 million of impairment charges primarily resulting from natural gas price declines since year end 2009.   The three properties subject to these impairment

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charges produce natural gas almost entirely. Separately, we also recorded a $4.1 million impairment charge for our only non-domestic oil and gas property (see "United Kingdom Property" below).

In the second quarter of 2009, we recorded an aggregate of approximately $63.1 million of impairment charges. These charges primarily reflected the approximate $51.5 million of impairment-related charges recorded to properties that were severely damaged by Hurricane Ike (as discussed below in Insurance). 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.

Exploration and Other

As of June 30, 2010, we capitalized approximately $3.2 million of costs associated with ongoing exploration and/or appraisal activities. Such capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur.

The following table details the components of exploration expense for the three and six month periods ended June 30, 2010 and 2009 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Delay rental and geological and geophysical costs	$ 1,182	$ 1,061	$ 1,528	$ 1,533
Dry hole expense	(10)	422	(190)	426
Total exploration expense	$ 1,172	$ 1,483	$ 1,338	$ 1,959

MMS Royalty Claims

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

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

United Kingdom Property

Since 2006, we have maintained an ownership interest in the Camelot field, located offshore in the North Sea. In 2007, we sold half of our 100% working interest in Camelot to a third party with whom we agreed to jointly pursue future development and production of the field. In February 2010, we acquired this third party thereby assuming its obligations, most notably the asset retirement obligation ("ARO"), related to its 50% working interest in the field. The following table contains the fair value of the assets acquired and liabilities assumed in our acquisition of this third party and its 50% working interest in the Camelot field (in thousands):

Cash (a)	$ 10,156
Deferred tax asset	2,083
Accrued liabilities	(452)
Asset retirement obligation	(5,841)
Gain on acquisition of assets	$ 5,946

a) At March 31, 2010, $10.0 million of this amount remained held in an escrow account and was restricted for future use to fund the asset retirement costs associated with Camelot field. The amount was released from escrow in the second quarter and is now unrestricted and classified with our cash and cash equivalents in the accompanying condensed consolidated balance sheet. The current classification of the asset retirement reflects the near-term probability of these activities occurring.

In connection with the valuation of assets acquired and liabilities assumed in this acquisition, we reassessed the fair value associated with our original 50% interest in the field. Based on these evaluations, it was concluded that an impairment of the property was required based on the unlikely probability of our expending the future capital necessary to further develop the Camelot field and our plans are to abandon the field over the near term. As a result, we recorded a $4.1 million impairment charge to fully impair the property. Accordingly, in our future estimates of proved reserves we will no longer consider the reserves associated with this field as proved but rather deem them as probable reserves.

Property Sales

In the first quarter of 2009, we sold our interest in East Cameron Block 316 for gross proceeds of approximately $18 million. We recorded an approximate $0.7 million gain from the sale of East Cameron Block 316 which was partially offset by the loss on the sale of the remaining 10% of our interest in the Bass Lite field at Atwater Block 426 in January 2009. In the second quarter of 2009, we sold three fields for gross proceeds of $0.8 million resulting in an aggregate gain of $1.2 million, including transfer of the respective field's asset retirement obligations.

Asset retirement obligations

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

Asset retirement obligation at December 31, 2009	$ 248,128
Liability incurred during the period (a)	17,392
Liability settled during the period	(38,496)
Revision in estimated cash flows	7,540
Accretion expense (included in depreciation and amortization)	7,943
Asset retirement obligations at June 30, 2010	$ 242,507

a) Amount primarily includes the acquisition of the remaining 50% working interest in the Camelot field in February 2010 (see "United Kingdom Property" above) and the additional scope of work associated with the development of the Phoenix field. Initial production was deferred from June 2010 to allow our HP I vessel to be contracted and used in the Gulf oil spill containment efforts. Following its release from the oil spill containment response contract, the HP I will mobilize to Phoenix field, where initial production is expected to commence late in the third quarter of 2010.

Insurance

In September 2008, we sustained damage to certain of our oil and gas production facilities from Hurricanes Gustav and Ike. While we sustained some damage to our own production facilities from Hurricane Ike, the larger issue in terms of production recovery involved damage to third party pipelines and onshore processing facilities. We carried comprehensive insurance on all of our operated and non-operated producing and non-producing properties. We record our hurricane-related costs as incurred. Insurance reimbursements were recorded when the realization of the claim for recovery of a loss is deemed probable.

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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 reflects 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 resulting from additional work performed and/or further evaluation of facilities on properties that were classified as a “total loss” following the storm. During the first half of 2010, we incurred a total of $3.6 million of additional hurricane-related repair costs.

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 reimbursement recently settled under our energy insurance policy (in thousands):

	Second Quarter 2009	Six Months Ended June 30, 2009
Oil and gas:		
Hurricane repair costs	$ 7,427	$20,163
ARO liability adjustments	43,812	43,812
Hurricane-related impairments	7,699	7,699
Insurance recoveries	(97,747)	(100,874)
Net (reimbursements) costs	$ (38,809)	$(29,200)
Contracting services:		
Hurricane repair costs	$ 317	$776
Insurance recoveries	(2,249)	(2,726)
Net (reimbursements) costs	(1,932)	(1,950)
Shelf Contracting:		
Hurricane repair costs	383	610
Insurance recoveries	(2,611)	(2,611)
Net (reimbursements) costs	(2,228)	(2,001)
Totals:		
Hurricane repair costs	8,127	21,549
ARO liability adjustments	43,812	43,812
Hurricane-related impairments	7,699	7,699
Insurance recoveries	(102,607)	(106,211)
Net reimbursements	$ (42,969)	$(33,151)

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Similar to last year, our 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 Catastrophic Bond instrument. The Catastrophic Bond provides for payments of negotiated amounts should the eye of a Category 2 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 $11.9 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, 2010 to September 30, 2010. As a result, we will charge to expense $9.4 million of our $11.9 premium in the third quarter of 2010 and $2.3 million of the premium will be charged to expense in the fourth quarter of 2010. The remaining $0.2 million will be charged to expense over first half of 2011. The expense associated with the Catastrophic Bond premium is recorded as a component of lease operating expense for our oil and gas operations.

Note 7 – Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. We had restricted cash totaling $35.5 million at June 30, 2010 and $35.4 million December 31, 2009 all of which was related to funds required to be escrowed to cover the future asset retirement obligations associated with our South Marsh Island Block 130 field. We have fully satisfied the escrow requirements under the escrow agreement and may use the restricted cash for the future asset retirement costs of the related field. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

The following table provides supplemental cash flow information for the three months ended June 30, 2010 and 2009 (in thousands):

	Six Months Ended June 30,	
	2010	2009
Interest paid, net of capitalized interest(1)	$ 27,847	$ 35,367
Income taxes paid	$ 6,642	$ 20,442

Non-cash investing activities for the six-month periods ended June 30, 2010 and 2009 included $32.0 million and $50.0 million, respectively, of accruals for capital expenditures. The accruals have been reflected in the condensed consolidated balance sheet as an increase in property and equipment and accounts payable.

Note 8 – Equity Investments

As of June 30, 2010, we have the following material investments, both of which are included within our Production Facilities segment and are accounted for under the equity method of accounting:

· Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. ("Enterprise"), formed Deepwater Gateway, L.L.C. ("Deepwater Gateway"), each with a 50% interest, to design, construct, install, own and operate a tension leg platform ("TLP") production hub primarily for Anadarko Petroleum Corporation's Marco Polo field in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $101.7 million and $103.3 million as of June 30, 2010 and December 31, 2009, respectively (including capitalized interest of $1.5 million at June 30, 2010 and December 31, 2009). Distributions from Deepwater Gateway, net to our interest, totaled $1.6 million and $3.9 million for the respective three month and six month periods ended June 30, 2010.

· Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, an affiliate of Enterprise. Independence Hub owns the "Independence Hub" platform located in Mississippi Canyon Block 920 in a water depth of 8,000 feet. First production through the facility commenced in July 2007. Our investment in Independence Hub was $85.1 million and $86.1 million as of June 30, 2010 and December 31, 2009, respectively (including capitalized interest of $5.4 million and $5.6 million at June 30, 2010 and December 31, 2009, respectively). Distributions from Independence Hub, net to our interest, totaled $5.8 million and $10.7 million for the three month and six month periods ended June 30, 2010, respectively.

The following presents selected summarized unaudited operating results for our Deepwater Gateway and Independence Hub equity investments for the three and six month periods ended June 30, 2010 and 2009 (in thousands):

	Deepwater Gateway Three Months Ended June 30,		Independence Hub Three Months Ended June 30,		Combined Three Months Ended June 30,	
	2010	2009	2010	2009	2010	2009
Revenues	$ 4,424	$ 1,691	$ 27,583	$33,155	$ 32,007	$ 34,846
Operating income	2,346	(469)	24,008	29,590	26,354	29,121
Net income	2,347	(464)	24,009	29,595	26,356	29,131
Equity in earnings	$ 1,174	$ (233)	$ 4,802	$5,919	$ 5,976	$ 5,686

	Deepwater Gateway Six Months Ended June 30,		Independence Hub Six Months Ended June 30,		Combined Six Months Ended June 30,	
	2010	2009	2010	2009	2010	2009
Revenues	$ 8,742	$ 8,333	$ 56,765	$ 66,771	$ 65,507	$ 75,104
Operating income	4,584	3,154	49,618	59,615	54,202	62,769
Net income	4,585	3,167	49,619	59,632	54,204	62,799
Equity in earnings	$ 2,293	$ 1,583	$ 9,924	$ 11,926	$ 12,217	$ 13,509

In February 2010, we announced the formation of a joint venture with Australian-based engineering and construction company, Clough Projects Australia Pty Ltd ("Clough"), to provide a range of subsea services to offshore operators in the Asia Pacific region. Services provided by the joint venture, named CloughHelix JV Co., will include subsea well intervention and well abandonment, SURF (subsea infrastructure, umbilical, riser and flowline installation), saturation and air diving, and subsea inspection, repair and maintenance services. The CloughHelix JV will integrate our well intervention equipment with Clough's new 12 man saturation diving system, to enable both to be deployed from the 118 meter long DP2 multiservice vessel, the Normand Clough, outfitted with a 250 ton active heave compensated crane. We recorded $4.3 million and $5.7 million of losses associated with our 50% interest in the joint venture for the three month and six month periods ended June 30, 2010, respectively. The losses primarily represented the mobilization costs of transporting the Normand Clough from the Gulf of Mexico to Singapore and other start up costs related to the joint venture. This joint venture is part of our Contracting Services segment.

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Note 9 – Long-Term Debt

Scheduled maturities of long-term debt and capital lease obligations outstanding as of June 30, 2010 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes (1)	MARAD Debt	Other(2)	Total
Less than one year	$ 4,326	$	$	$	$ 4,533	$ 2,537	$ 11,396
One to two years	4,326				4,760		9,086
Two to three years	4,326				4,997		9,323
Three to four years	399,625				5,247		404,872
Four to five years					5,508		5,508
Over five years			550,000	300,000	92,005		942,005
Total debt	412,603		550,000	300,000	117,050	2,537	1,382,190
Current maturities	(4,326)				(4,533)	(2,537)	(11,396)
Long-term debt, less current maturities	$408,277	$	$ 550,000	$ 300,000	$ 112,517	$	$1,370,794
Unamortized debt discount (3)				(22,800)			(22,800)
Long-term debt	$408,277	$	$ 550,000	$ 277,200	$ 112,517	$	$1,347,994

(1) Beginning in December 2012, the holders may require us to repurchase the notes or we may at our own option elect to repurchase notes. Notes will not mature until March 2025.
(2) Represents the balance of the loan provided by Kommandor RØMØ to Kommandor LLC as of June 30, 2010.
(3) Reflects debt discount resulting from adoption of new provisions of ASC Topic No. 470-20 "Convertible Debt and Other Options" on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest charges through 2012.

At June 30, 2010, unsecured letters of credit issued totaled approximately $57.6 million (see "Credit Agreement" below). These letters of credit primarily guarantee various contract bidding, contractual performance, including asset retirement obligations, and insurance activities. The following table details our interest expense and capitalized interest for the three and six month periods ended June 30, 2010 and 2009:

	Three Months Ended June 30,	Six Months Ended June 30,

	2010	2009	2010	2009
		(in thousands)		
Interest expense	$ 24,597	$ 27,612	$ 48,946	$ 57,463
Interest income	(199)	(98)	(397)	(362)
Capitalized interest	(3,875)	(11,870)	(12,391)	(19,490)
Interest expense, net	$ 20,523	$ 15,644	$ 36,158	$ 37,611

Included below is a summary of certain components of our indebtedness. For additional information regarding our debt see Note 10 of our 2009 Form 10-K.

Senior Unsecured Notes

In December 2007, we issued $550 million of 9.5% Senior Unsecured Notes due 2016 ("Senior Unsecured Notes"). Interest on the Senior Unsecured Notes is payable semiannually in arrears on each January 15 and July 15, commencing July 15, 2008. The Senior Unsecured Notes are fully and unconditionally guaranteed by substantially all of our existing restricted domestic subsidiaries, except for Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our indebtedness and/or our restricted subsidiaries' indebtedness are required to guarantee the Senior Unsecured Notes. Our foreign subsidiaries are not guarantors. We used the proceeds from the Senior Unsecured Notes to repay outstanding indebtedness under our Credit Agreement (see below).

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Credit Agreement

In July 2006, we entered into a credit agreement (the “Credit Agreement”) under which we borrowed $835 million in a term loan (the “Term Loan”) and were initially able to borrow up to $300 million (the “Revolving Loans”) under a revolving credit facility (the “Revolving Credit Facility”). The parties have amended the Credit Agreement three times, most recently in February 2010, to address certain issues with regard to covenants, maturity and the borrowing limits under the Revolving Credit Facility. For additional information regarding the current terms of our credit facility see Note 9 of our Quarterly Report on Form 10-Q for the period ending March 31, 2010.

The proceeds from the Term Loan were used to fund the cash portion of the acquisition of Remington Oil and Gas Corporation in July 2006. The Term Loan currently bears interest either at the one-, three- or six-month LIBOR at our election plus a margin of between 2.25% and 2.5% depending on current leverage ratios. Our average interest rate on the Term Loan for the six month periods ended June 30, 2010 and 2009 was approximately 2.9% and 4.9%, respectively, including the effects of our interest rate swaps (Note 18). The Term Loan is scheduled to mature on July 1, 2013.

The original maturity date of the Revolving Credit Facility was July 1, 2011. In the fourth quarter of 2009, we increased the Revolving Credit Facility and extended its maturity date to November 30, 2012. As a consequence of the foregoing, the borrowing limit under the Revolving Credit Facility was increased by amendment to $435 million, effective December 31, 2009. This amount will decrease to $410 million beginning July 1, 2011 and will stay at that level through the maturity of the Revolving Credit Facility on November 30, 2012. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit. At June 30, 2010, we had no amounts drawn on the Revolving Credit Facility and our availability under the Revolving Credit Facility totaled $377.4 million, net of $57.6 million of letters of credit issued.

The Revolving Loans bear interest based on one-, three- or six-month LIBOR rates or on Base Rates at our election plus an applicable margin. The margin ranges from 1.0% to 4.5%, depending on our consolidated leverage ratio. We did not have any borrowings under our Revolving Loans in the six months ended June 30, 2010. Our average interest rate on the Revolving Loans for the six months ended June 30, 2009 was approximately 3.4%.

The Credit Agreement contains various covenants regarding, among other things, collateral, capital expenditures, investments, dispositions, indebtedness and financial performance that are normal for this type of financing and for companies in our industry.

As the rates for our Term Loan are subject to market influences and will vary over the term of the Credit Agreement, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. In January 2010, we entered into $200 million, two-year interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan (Note 18).

Convertible Senior Notes

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

The Convertible Senior Notes can be converted prior to the stated maturity (March 2025) under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. No conversion triggers were met during the six-month period ended June 30, 2010. The first dates for early redemption of the Convertible Senior Notes are in December 2012, with the holders of the Convertible Senior Notes being able to put them to us on December 15, 2012 and our being able to call the Convertible Senior Notes at any time after December 20, 2012. The effective interest rate for the Convertible Senior Notes is 6.6%.

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Our average share price for all the periods presented in this Quarterly Report on Form 10-Q was below the $32.14 per share conversion price. As a result of our share price being lower than the $32.14 per share conversion price for these periods there are no shares included in our diluted earnings per share calculation associated with the assumed conversion of our Convertible Senior Notes. In the event our average share price exceeds the conversion price, there would be a premium, payable in shares of common stock, in addition to the principal amount, which is paid in cash, and such shares would be issued on conversion. The Convertible Senior Notes are convertible into a maximum 13,303,770 shares of our common stock.

MARAD Debt

This U.S. government guaranteed financing ("MARAD Debt") is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration and was used to finance the construction of the Q4000 vessel. The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the Q4000, with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027).

Other

In accordance with our Credit Agreement and our Senior Unsecured Notes, Convertible Senior Notes and MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. The Senior Unsecured Notes and Credit Agreement contain provisions that limit our ability to incur certain types of additional indebtedness. As of June 30, 2010, we were in compliance with all of our debt covenants and restrictions.

Deferred financing costs of $29.3 million at June 30, 2010 and $30.1 million at December 31, 2009 are included in other assets, net and are being amortized over the life of the respective loan agreements.

Note 10 – Income Taxes

The effective tax rate for the three month and six month periods ended June 30, 2010 was a benefit of 38.1% and 37.0%, respectively, due to increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions. The effective tax rate for the three month and six month periods ended June 30, 2009 was an expense of 35.5% and 35.8%, respectively, as a result of the consolidation of CDI in 2009.

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

Note 11 – Comprehensive Income (Loss)

The components of total comprehensive income (loss) for the three and six month periods ended June 30, 2010 and 2009 were as follows (in thousands):

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income (loss), including noncontrolling interests	$(85,073)	$113,089	$(102,075)	$225,844
Other comprehensive income (loss), net of tax				
Foreign currency translation gain	(3,106)	30,650	(13,808)	27,032
Unrealized loss on hedges, net	2,063	(8,873)	16,103	(13,338)
Unrealized loss on investment available for sale	(481)		(556)	
Total Comprehensive income (loss)	(86,597)	134,866	(100,336)	239,538
Less: Comprehensive loss applicable to noncontrolling interest		(12,333)		(17,880)
Total other comprehensive income (loss) applicable to Helix	$(86,597)	$122,533	$(100,336)	$221,658

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

	June 30, 2010	December 31, 2009
Cumulative foreign currency translation adjustment	$ (26,065)	$ (12,257)
Unrealized gain (loss) on hedges, net	7,006	(9,097)
Unrealized loss on investment available for sale	(1,443)	(887)
Accumulated other comprehensive loss	$ (20,502)	$ (22,241)

Note 12 – Earnings Per Share

We have shares of restricted stock issued and outstanding, some of which remain subject to certain vesting requirements. Holders of such shares of unvested restricted stock are entitled to the same liquidation and dividend rights as the holders of our outstanding common stock and are thus considered participating securities. Under the applicable guidance, the undistributed earnings for each period are allocated based on the participation rights of both the common shareholders and holders of any participating securities as if earnings for the respective periods had been distributed. Because both the liquidation and dividend rights are identical, the undistributed earnings are allocated on a proportionate basis. Further, we are required to compute earnings per share ("EPS") amounts under the two class method in periods in which we have earnings from continuing operations. For periods in which we have a net loss we do not use the two class method as holders of our restricted shares are not contractually obligated to share in such losses.

Basic EPS is computed by dividing the net income available to common shareholders by the weighted average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computation of basic and diluted EPS amounts for the three and six months ended June 30, 2010 and 2009 follows (in thousands):

	Three Months Ended	Three Months Ended

	June 30, 2010		June 30, 2009	
	Income	Shares	Income	Shares
Basic:				
Net income (loss) applicable to common shareholders	$ (85,551)		$ 100,219	
Less: Undistributed net income allocable to participating securities			(1,526)	
Undistributed net income (loss) applicable to common shareholders	(85,551)		98,693	
(Income) loss from discontinued operations	17		(9,836)	
Add: Undistributed net income from discontinued operations allocable to participating securities			150	
Income (loss) per common share – continuing operations	$ (85,534)	104,125	$ 89,007	96,936

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	Three Months Ended June 30, 2010		Three Months Ended June 30, 2009	
	Income	Shares	Income	Shares
Diluted:				
Net income (loss) per common share – continuing operations – Basic	$ (85,534)	104,125	$ 89,007	96,936
Effect of dilutive securities:				
Stock options				24
Undistributed earnings reallocated to participating securities			116	
Convertible Senior Notes				
Convertible preferred stock			250	9,035
Income (loss) per common share continuing operations	(85,534)		89,373	
Income (loss) per common share discontinued operations	(17)		9,836	
Net income (loss) per common share	$ (85,551)	104,125	$ 99,209	105,995

	Six Months Ended June 30, 2010		Six Months Ended June 30, 2009	
	Income	Shares	Income	Shares
Basic:				
Net income (loss) applicable to common shareholders	$ (103,442)		$ 153,669	
Less: Undistributed net income allocable to participating securities			(2,305)	
Undistributed net income (loss) applicable to common shareholders	(103,442)		151,364	
(Income) loss from discontinued operations	44		(7,282)	
Add: Undiscounted net income from discontinued operations allocable to participating securities			109	
Income (loss) per common share – continuing operations	$ (103,398)	103,610	$ 144,191	96,077

	Six Months Ended June 30, 2010		Six Months Ended June 30, 2009	
	Income	Shares	Income	Shares
Diluted:				
Net income (loss) per common share – continuing operations – Basic	$ (103,398)	103,610	$ 144,191	96,077
Effect of dilutive securities:				

Stock options				
Undistributed earnings reallocated to participating securities			203	
Convertible Senior Notes				
Convertible preferred stock			563	9,923
Income (loss) per common share continuing operations	(103,398)		144,957	
Income (loss) per common share discontinued operations	(44)		7,282	
Net income (loss) per common share	$(103,442)	103,610	$ 152,239	106,000

We had a net loss from continuing operations for both the three and six month periods ended June 30, 2010. Accordingly, we had no dilutive securities during these reporting periods as their inclusion would have an anti-dilutive effect on our EPS calculation, meaning it would increase our reported EPS amount. The following table provides the effect the excluded securities would have had on our diluted shares calculation for the three and six month periods ended June 30, 2010 assuming we had earnings from continuing operations (in thousands):

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	Three Months	Six Months
Diluted shares (as reported)	104,125	103,610
Stock options	94	80
Convertible preferred stock	1,195	1,689
Total	105,414	105,379

There were no dilutive stock options for the six month period ended June 30, 2009 as the option strike price was below the average market price for the period ($7.50 per share). The cumulative $53.4 million of beneficial conversion charges that were realized and recorded during the first quarter of 2009 following the transactions affecting our convertible preferred stock (Note 5) are not included as an addition to adjust earnings applicable to common stock for our diluted earnings per share calculation. The diluted EPS amount included the $0.3 million and $0.6 million of dividends and related costs associated with the assumed conversion of the convertible preferred stock for the three and six month periods ended June 30, 2009.

Note 13 – Stock-Based Compensation Plans

We have two stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the "1995 Incentive Plan") and the 2005 Long-Term Incentive Plan, as amended (the "2005 Incentive Plan"). As of June 30, 2010, there were approximately 1.3 million shares available for grant under our 2005 Incentive Plan.

During the first half of 2010, we made the following restricted share or restricted stock unit grants to certain key executives, selected management employees and non-employee members of the board of directors under the 2005 Incentive Plan:

Date of Grant	Type	Shares	Market Value Per Share	Vesting Period
January 4, 2010	(1)	452,849	$11.75	20% per year over five years
January 4, 2010	(2)	23,569	11.75	20% per year over five years
January 4, 2010	(1)	1,197	11.75	100% on January 1, 2012
April 1, 2010	(1)	4,029	13.03	100% on January 1, 2012

(1) Restricted shares
(2) Restricted stock units

There were no stock option grants in the three and six month periods ended June 30, 2010 and 2009.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. There was no compensation cost associated with stock options for the three and six month periods ended June 30, 2010 as all outstanding stock options have vested. We recorded $0.1 million of compensation expense related to the final vesting of stock options in the first quarter of 2009. For the three and six month periods ended June 30, 2010, $2.1 million and $4.6 million, respectively, was recognized as compensation expense related to restricted shares as compared with $2.3 million and $4.6 million during the three and six month periods ended June 30, 2009, respectively.

In January 2009, we adopted the 2009 Long-Term Incentive Cash Plan (the "2009 LTI Plan") to provide long term cash based compensation to eligible employees. Under the terms of the 2009 LTI Plan, the majority of the cash awards are fixed sum amounts payable over a five year vesting period. However, some of the cash awards are indexed to our Company common stock price and the payment amount will fluctuate based on the common stock's performance. This share based component is considered a liability plan under the guidance of ACS Topic No. 718 "Compensation – Stock Compensation" and as such is re-measured to fair value each reporting period with corresponding changes being recorded as a charge to earnings as appropriate.

The total awards made under the 2009 LTI Plan totaled $14.7 million in 2009, including $8.1 million for our executive officers, which vest over a five year period. In January 2010, $10.1 million was awarded under the 2009 LTI Plan to eligible employees, including $6.0 million to our executive officers and other members of senior management. Total compensation under the 2009 LTI plan totaled $0.9 million and $2.6 million for the three and six month periods ended June 30, 2010, respectively. For the three and six month periods ended June 30, 2009, total compensation under the 2009 LTI plan totaled $0.7 million and $1.4 million, respectively.

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

Note 14 – Business Segment Information

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

We evaluate our performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. For our Production Facilities segment, we account for our investments in the Deepwater Gateway and Independence Hub under the equity method and we consolidate our investment in the HP I.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Revenues				
Contracting Services	$ 202,317	$ 239,476	$ 356,517	$ 470,331
Shelf Contracting	–	197,656	–	404,709
Oil and Gas (1)	102,586	89,992	193,301	250,173
Production Facilities(2)	21,391	1,120	22,711	1,120
Intercompany elimination	(27,032)	(33,605)	(71,697)	(60,719)
Total	$ 299,262	$ 494,639	$ 500,832	$ 1,065,614
Income (loss) from operations				
Contracting Services	$ 43,781	$ 34,636	$ 71,267	$ 74,384
Shelf Contracting	–	38,145	–	59,077

Oil and Gas (1)		(154,943)		42,945		(155,607)		188,128
Production Facilities (2)		12,977		(1,018)		12,940		(1,152)
Corporate (3)		(12,597)		(11,253)		(35,475)		(21,772)
Intercompany elimination		(6,114)		(1,631)		(18,419)		(1,921)
Total	$	(116,896)	$	101,824	$	(125,294)	$	296,744
Equity in earnings of equity investments	$	1,656	$	6,264	$	6,711	$	13,767

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

(2) Included the operating results related to the HP I.

(3) Included $13.8 million of $17.5 million settlement of a third party claim against us in March 2010 (Note 16).

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Intercompany segment revenues during the three and six month periods ended June 30, 2010 and 2009 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Contracting Services	$ 24,426	$ 28,951	$ 68,167	$ 52,854
Shelf Contracting	–	4,654	–	7,865
Production Facilities	2,606	–	3,530	–
Total	$ 27,032	$ 33,605	$ 71,697	$ 60,719

Intercompany segment gross profit (losses) during the three and six month periods ended June 30, 2010 and 2009 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Contracting Services	$ 3,701	$ 1,551	$ 15,143	$ 1,447
Shelf Contracting	–	109	–	503
Production Facilities	2,413	(29)	3,293	(29)
Total	$ 6,114	$ 1,631	$ 18,436	$ 1,921

Our identifiable assets as of June 30, 2010 and December 31, 2009 were as follows:

	June 30, 2010	December 31, 2009
	(in thousands)	
Identifiable Assets		
Contracting Services	$ 1,757,811	$ 1,738,005
Oil and Gas	1,321,817	1,541,153
Production Facilities	526,120	499,497
Assets of discontinued operations	825	878
Total	$ 3,606,573	$ 3,779,533

Note 15 – Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison, a Deepwater Gulf of Mexico prospect. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or "OKCD"), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix's 20% working interest. Our Chief Executive Officer, Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 80.4% of the partnership. In 2000, OKCD also awarded Class B income participations to key Helix employees. Production began in December 2003. Our payments to OKCD totaled $3.0 million and $6.1 million for the three and six month periods ended June 30, 2010, respectively, and $2.6 million and $5.4 million in the three and six month periods ended June 30, 2009, respectively.

Note 16 – Commitments and Contingencies

Commitments

We completed the conversion of the Caesar (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. The Caesar was placed in service in the second quarter of 2010. There will be some additional capital upgrades to the vessel that will be performed at a later date. Capitalized costs incurred for the vessel as of June 30, 2010 totaled $279.6 million (including capitalized interest of $24.4 million). There were $4.9 million of additional committed capital expenditures for the Caesar at June 30, 2010. We also plan for future spending of approximately $23.4 million of capital for additional Caesar upgrades.

Further, we, along with Kommandor Rømø, a Danish corporation, formed a joint venture company called Kommandor and converted a ferry vessel into a floating production unit, the HP I. The total cost of the ferry and the conversion was approximately $150 million. We provided $98.9 million in interim construction financing to the joint venture. During 2009, $58.8 million of this amount was converted to equity in our investment in Kommandor. Kommandor Rømø provided a $5.0 million loan to Kommandor, the remaining balance of which was $2.5 million at June 30, 2010.

Upon completion of the initial conversion, which occurred in April 2009, we chartered the HP I from Kommandor, and have installed, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the HP I. This work was completed in the second quarter of 2010 and the HP I is now in service at the oil spill site at the Macondo well. Following its release from the oil spill site, the HP I will mobilize to the Phoenix field where production is expected to commence late in the third quarter of 2010. The final total cost of processing facilities approximates $200 million (including capitalized interest of $16.9 million). As of June 30, 2010, we have committed to spend $3.7 million in additional capital expenditures on our HP I processing facilities. We have consolidated Kommandor in all periods presented in the accompanying consolidated financial statements. The results of Kommandor are included within our Production Facilities segment.

As of June 30, 2010, we planned to spend approximately $5.8 million for additional capital improvements to the newly constructed Well Enhancer vessel and have committed to spend $25.1 million in additional capital expenditures for exploration, development and drilling costs related to our oil and gas properties.

Contingencies

We are involved in various legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act based on alleged negligence. In addition, from time to time we incur other claims, such as contract disputes, in the normal course of business.

Litigation and Claims

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

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In 2008, we were subcontracted by the prime contractor to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2008 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivable and claims yet to be collected. We have requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor has also requested arbitration in which it asserts certain counterclaims against us. If we are not successful in resolving these matters through ongoing discussions with the prime contractor then arbitration in India remains a potential remedy. At the time of this filing we believe we will collect our trade receivable balance and we are continuing our efforts to actively pursue our other claim amounts but do not yet have the approvals necessary to recognize additional revenue.

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

Note 17 – Fair Value Measurements and Recent Accounting Standards

Fair Value Measurements

We follow the provisions of the ASC 820, Fair Value Measurements and Disclosures, for financial assets and liabilities that are measured and reported at fair value on a recurring basis. ASC 820 establishes a hierarchy for inputs used in measuring fair value. The fair value is to be calculated based on assumptions that market participants would use in pricing assets and liabilities and not on assumptions specific to the entity. The statement requires that each asset and liability carried at fair value be classified into one of the following categories:

- Level 1. Observable inputs such as quoted prices in active markets;
- Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and
- Level 3. Unobservable inputs in which there is little or no market data, which require the reporting entity to develop its own assumptions.

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

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

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at June 30, 2010 (in thousands):

	Level 1	Level 2 (1)	Level 3	Total	Valuation Technique
Assets:					
Oil and gas swaps and collars	$–	$15,373	$–	$15,373	(c)
Investment in Cal Dive	2,925	–	–	2,925	(a)
Liabilities:					
Oil and gas swaps and collars	–	2,804	–	2,804	(c)

Fair value of long term debt(2)	1,148,754	127,819		1,276,573	(a), (b)
Foreign currency forwards	–	1,231	–	1,231	(c)
Interest rate swaps	–	1,695	–	1,695	(c)
Total net liability	$1,145,829	$118,176	$–	$1,264,005	

(1) Unless otherwise indicated, the fair value of our Level 2 derivative instruments reflects our best estimate and is based upon exchange or over-the-counter quotations whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, we utilize other valuation techniques or models to estimate market values. These modeling techniques require us to make estimations of future prices, price correlation and market volatility and liquidity. Our actual results may differ from our estimates, and these differences can be positive or negative.

(2) See Note 9 for additional information regarding our long term debt. The fair value of our long term debt at June 30, 2010 is as follows:

	Fair Value	Carrying Value
Term Loan (matures July 2013)	$ 381,658	$ 412,603
Revolving Credit Facility (matures November 2012)	–	–
Convertible Senior Notes (matures March 2025)	261,489	277,200
Senior Unsecured Notes (matures January 2016)	503,250	550,000
MARAD Debt (matures August 2027) (a)	127,819	117,050
Loan Note(b)	2,537	2,537
Total	$ 1,276,753	$ 1,359,390

(a) The estimated fair value of all debt, other than MARAD Debt and Loan Note, was determined using Level 1 inputs using the market approach. The fair value of the MARAD debt was determined using a third party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other governmental obligations in the market place with similar terms. The fair value of the MARAD debt was estimated using Level 2 fair value inputs using the cost approach.

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

We account for long-lived assets in accordance with ASC 360-10-35, Impairment of Disposal of Long-Lived Assets, and review long-lived assets for impairment whenever events occur or changes in circumstances indicate that the carrying amount of assets may not be recoverable. In such evaluation, the estimated future undiscounted cash flows to be generated by the asset are compared with the carrying value of the asset to determine if an impairment may be required. For our oil and gas properties, the estimated future undiscounted cash flows are based on estimated crude oil and natural gas proved and probable reserves and published future market commodity prices, estimated operating costs and estimates of future capital expenditures. If the estimated undiscounted cash flows for a particular asset are not sufficient to cover the carrying value of the asset the asset is impaired and its carrying value is reduced to the current fair value. The fair value of these assets is determined using an income approach by calculating present value of future cash flows attributable to the asset based on market information (such as forward commodity prices), estimates of future costs and estimated proved and probable reserve quantities. These fair value measurements fall within Level 3 of the fair value hierarchy.

At June 30, 2010 we impaired 15 of our Gulf of Mexico properties as a result of reductions in estimates of proved reserves. The total amount of these impairment charges were $159.9 million, which reduced the carrying value of these properties to their aggregate fair value of $62.5 million. In the first quarter of 2010, we impaired three of our natural gas producing properties following a significant drop in natural gas prices during the period . The total amount of the impairment charges were $7.0 million, which reduced these properties to their aggregate fair value of $28.2 million. See Note 6 for additional information regarding our oil and gas property impairment charges.

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Recent Accounting Pronouncements

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

Note 18 – Derivative Instruments and Hedging Activities

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

We engage only in cash flow hedges. Hedges of cash flow exposure are entered into to hedge a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in the derivative fair values that are designated as cash flow hedges are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income, a component of shareholders’ equity, until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge’s change in fair value is recognized immediately in earnings. In addition, any change in the fair value of a derivative that does not qualify for hedge accounting is recorded in earnings in the period in which the change occurs. Further, when we have obligations and receivables with the same counterparty, the fair value of the derivative liability and asset are presented at net value.

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

Commodity Price Risks

We currently manage commodity price risks through various financial costless collars and swap instruments covering a portion of our anticipated oil and natural gas production for 2010. In the past, we have also utilized forward sales contracts that require physical delivery of oil and natural gas. We seek hedge accounting treatment for our oil and gas commodity derivative contracts. However, due to disruptions in our production as a result of damages caused by the hurricanes in third quarter 2008, most of our financial commodity contracts in place at March 31, 2009 no longer qualified for hedge accounting. Our forward sales contracts were not within the scope of SFAS No. 133 as they qualified for the normal purchases and sales scope exception. However, due to disruptions in our production as a result of damages caused by the hurricanes, as mentioned above, they no longer qualified for the scope exception. As a result, both our oil and natural gas commodity contracts and our natural gas normal purchase and sale contracts were required to be mark-to-market effective March 31, 2009. Changes in the fair value of these mark to market oil and gas derivative contracts are reflected in our accompanying condensed consolidated statements of operations in the line titled “Gain on oil and gas derivative contracts.”

Until June 2010 all of our oil and gas commodity contracts for expected 2010 production qualified for hedge accounting. In June 2010 some of our oil contracts for 480 MBbl covering portions of our anticipated production during the third quarter of 2010 ceased to qualify for hedge accounting as a result of our decision to contract the HP

I to BP to assist in the oil spill containment response rather than commencing production from our Phoenix field. The HP I will return to the Phoenix field following its release from the oil spill site and first production is now anticipated late in the third quarter of 2010. All of our remaining commodity derivative contracts are designated as cash flow hedges remain effective and qualify for hedge accounting as of June 30, 2010 (Note 18). The amount of ineffectiveness related to our oil and gas commodity contracts was immaterial for all periods presented in this Quarterly Report on Form 10-Q.

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As of June 30, 2010, we have the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 1,710 MMBbl of oil and 16.4 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			(per barrel)
July 2010 — December 2010	Collar	100 MBbl	$62.50-$80.73
July 2010 — December 2010	Swap	105 MBbl	$76.55
October 2010 — December 2010	Swap	160 MBbl	$81.44
Natural Gas:			(per Mcf)
July 2010 — December 2010	Swap	970.0 Mmcf	$5.81
July 2010 — December 2010	Collar	1,012.0 Mmcf	$6.00 — $6.70
January 2011 — December 2011	Swap	375.0 Mmcf	$5.44

In July 2010, we entered into contracts for 450 MBbls of oil at a contract price of $82.00 per barrel, representing a portion of our anticipated production for 2011. Changes in NYMEX oil and gas strip prices would, assuming all other things being equal, cause the fair value of these instruments to increase or decrease inversely to the change in NYMEX prices.

Variable Interest Rate Risks

As some of our long-term debt is subject to market influences and have variable interest rates, in January 2010 we entered into various interest rate swaps to stabilize cash flows relating to interest payments for $200 million of our Term Loan debt under our Credit Agreement (Note 9). These monthly contracts will mature in January 2012. Changes in the interest rate swap fair value are deferred to the extent the swap is effective and are recorded as a component of accumulated other comprehensive income until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings within the line titled “net interest expense”. Ineffectiveness related to our interest swaps was immaterial for all periods presented in this Quarterly Report on Form 10-Q.

Foreign Currency Exchange Risks

Because we operate in various regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar. We entered into various foreign currency forwards to stabilize expected cash outflows relating to certain shipyard contracts where the contractual payments are denominated in Euros and expected cash outflows relating to certain vessel charters denominated in British pounds. We will have open foreign exchange contracts until the last one settles in June 2012.

Quantitative Disclosures Related to Derivative Instruments

The following tables present the fair value and balance sheet classification of our derivative instruments as of June 30, 2010 and December 31, 2009. As required by ASC Topic No. 815 “Derivatives and Hedging”, the fair value amounts below are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. As a result, the amounts below may not agree with the amounts presented on our condensed consolidated balance sheet and the fair value information presented for our derivative instruments (Note 17).

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

	As of June 30, 2010		As of December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Asset Derivatives:				
Oil contracts	Other current assets	$ 368	Other current assets	$ —
Natural gas contracts	Other current assets	13,106	Other current assets	5,071
Natural gas contracts	Other assets, net	67	Other assets, net	—
Interest rate swaps	Other assets, net	—	Other assets, net	—
		$ 13,541		$ 5,071

	As of June 30, 2010		As of December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Liability Derivatives:				
Oil contracts	Accrued liabilities	$ 2,804	Accrued liabilities	$ 19,477
Natural gas contracts	Accrued liabilities	—	Accrued liabilities	59
Interest rate swaps	Accrued liabilities	1,368	Accrued liabilities	—
Interest rate swaps	Other liabilities	327	Other liabilities	—
		$ 4,499		$ 19,536

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

	As of June 30, 2010		As of December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
		(in thousands)		
Asset Derivatives:				
Natural gas contracts	Other current assets	$ —	Other current assets	$ —
Oil contracts	Other current assets	1,832	Other current assets	—
Foreign exchange forwards	Other current assets	—	Other current assets	1,143
Foreign exchange forwards	Other assets, net	—	Other assets, net	931

		$ 1,832		$ 2,074
Liability Derivatives:				
Foreign exchange forwards	Accrued liabilities	936	Accrued liabilities	—
Foreign exchange forwards	Other liabilities	295	Other liabilities	—
		$ 1,231		$ —

The following tables present the impact that derivative instruments designated as cash flow hedges had on our accumulated comprehensive loss and our condensed consolidated statements of operations for the three and six month periods ended June 30, 2010 and 2009.

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2010(1)	2009	2010(1)	2009
	(in thousands)			
Oil and natural gas commodity contracts	$ 2,575	$ (10,110)	$ 17,205	$ (14,377)
Foreign exchange forwards	—	26	—	(556)
Interest rate swaps	(512)	1,211	(1,102)	1,595
	$ 2,063	$ (8,873)	$ 16,103	$ (13,338)

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(1) All unrealized gains (losses) related to our derivatives are expected to be reclassified into earnings within the next 12 months, except for amounts related to our interest swaps and foreign exchange forwards, for which we have open contracts that have maturities through January and June of 2012, respectively.

	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 June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Oil and natural gas commodity contracts	Oil and gas revenue	$ 9,663	$ 6,275	$ 10,464	$ 15,861
Interest rate swaps	Net interest expense and other	(469)	(631)	(887)	(1,285)
		$ 9,194	$ 5,644	$ 9,577	$ 14,576

The following table presents the impact of derivative instruments that no longer qualify for hedge accouting or were not designated as hedges on our condensed consolidated income statement for the three and six month periods ended June 30, 2010 and 2009 :

	Location of Gain (Loss) Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives (in thousands) Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Natural gas contracts	Gain on oil and gas derivative contracts	$ 2,482	$ 4,122	$ 2,482	$ 78,730
Foreign exchange forwards	Net interest expense and other	(398)	4,497	(3,305)	5,143
Interest rate swaps	Net interest expense and other	—	(283)	—	(295)
		$ 2,084	$ 8,336	$ (823)	$ 83,578

Note 19 – Share Repurchase Program

In June 2009, we announced that we intended to purchase up to 1.5 million shares plus an amount equal to additional shares granted under the stock-based compensation plans (Note 13) of our common stock as permitted under our Credit Agreement. 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 June 30, 2010, we had repurchased a total of 1,752,831 shares of our common stock for $21.5 million or an average of $12.28 per share. In early July 2010, we purchased the remaining 223,487 shares currently available under this plan for $2.5 million or an average $11.21 per share. We retire all shares repurchased.

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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 subsidies were never guarantors of the Senior Unsecured Notes). Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guaranty arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is presented on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries' cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries relate primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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

	As of June 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 251,755	$ 5,035	$ 13,211	$ —	$ 270,001
Accounts receivable, net	48,594	76,445	50,201	—	175,240
Unbilled revenue	10,494	—	18,643	—	29,137
Income taxes receivable	57,289	—	18,635	(57,785)	18,139
Other current assets	51,752	53,194	15,882	(18,297)	102,531
Total current assets	419,884	134,674	116,572	(76,082)	595,048
Intercompany	29,528	225,128	(180,176)	(74,480)	—
Property and equipment, net	250,258	1,717,731	702,722	(5,151)	2,665,560
Other assets:					
Equity investments	2,034,923	32,754	187,694	(2,067,677)	187,694
Goodwill	—	45,107	31,027	—	76,134
Other assets, net	47,801	39,658	28,287	(33,609)	82,137
Due from subsidiaries/parent	109,138	90,455	—	(199,593)	—
	$ 2,891,532	$ 2,285,507	$ 886,126	$ (2,456,592)	$ 3,606,573
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities:					

Accounts payable	$ 53,794	$ 82,418	$ 27,763	$ —	$ 163,975
Accrued liabilities	81,351	93,273	27,802	(272)	202,154
Income taxes payable	—	75,333	—	(75,333)	—
Current maturities of long-term debt	4,326	—	24,821	(17,751)	11,396
Total current liabilities	139,471	251,024	80,386	(93,356)	377,525
Long-term debt	1,235,477	—	112,517	—	1,347,994
Deferred income taxes	151,339	155,261	85,826	(8,774)	383,652
Asset retirement obligations	—	165,799	—	—	165,799
Other long-term liabilities	1,326	2,992	714	77	5,109
Due to parent	—	—	134,623	(134,623)	—
Total liabilities	1,527,613	575,076	414,066	(236,676)	2,280,079
Convertible preferred stock	1,000	—	—	—	1,000
Total equity	1,362,919	1,710,431	472,060	(2,219,916)	1,325,494
	$ 2,891,532	$ 2,285,507	$ 886,126	$ (2,456,592)	$ 3,606,573

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

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

Asset retirement obligations					
Other long-term liabilities	924	2,495	766	77	4,262
Due to parent	—	—	99,352	(99,352)	—
Total liabilities	1,515,888	640,213	378,198	(188,228)	2,346,071
Convertible preferred stock	6,000	—	—	—	6,000
Total equity	1,461,243	1,759,506	481,166	(2,274,453)	1,427,462
	$ 2,983,131	$ 2,399,719	$ 859,364	$ (2,462,681)	$ 3,779,533

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

	Three Months Ended June 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$33,670	$ 186,247	$ 100,086	$ (20,741)	$ 299,262
Cost of sales	18,158	317,157	72,345	(13,580)	394,080
Gross profit (loss)	15,512	(130,910)	27,741	(7,161)	(94,818)
Gain on oil & gas derivative contracts	—	2,482	—	—	2,482
Loss on sale of assets	—	—	(14)	—	(14)
Selling and administrative expenses	(13,583)	(7,834)	(3,531)	402	(24,546)
Income (loss) from operations	1,929	(136,262)	24,196	(6,759)	(116,896)
Equity in earnings of investments	(69,604)	3,612	1,656	65,992	1,656
Net interest expense and other	(15,292)	(5,002)	(1,888)	—	(22,182)
Income (loss) before income taxes	(82,967)	(137,652)	23,964	59,233	(137,422)
Provision (benefit) for income taxes	(1,872)	(49,351)	1,221	(2,364)	(52,366)
Income from continuing operations	(81,095)	(88,301)	22,743	61,597	(85,056)
Discontinued operations, net of tax	(27)	—	10	—	(17)
Net income (loss) applicable to Helix	(81,122)	(88,301)	22,753	61,597	(85,073)
Less:net income applicable to noncontrolling interests	—	—	—	(444)	(444)
Preferred stock dividends	(34)	—	—	—	(34)
Net income (loss) applicable to Helix common shareholders	$(81,156)	$ (88,301)	$ 22,753	$ 61,153	$ (85,551)

	Three Months Ended June 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$93,906	$176,474	$ 255,165	$ (30,906)	$ 494,639
Cost of sales	79,650	118,281	190,069	(29,117)	358,883
Gross profit (loss)	14,256	58,193	65,096	(1,789)	135,756

Gain on oil & gas derivative contracts	—	4,121	—	—	4,121
Gain on sale of assets	—	1,319	—	—	1,319
Selling and administrative expenses	(12,770)	(7,610)	(20,062)	1,070	(39,372)
Income (loss) from operations	1,486	56,023	45,034	(719)	101,824
Equity in earnings of investments	71,904	1,642	6,625	(73,907)	6,264
Gain on sale of Cal Dive common stock	59,442	—	—	—	59,442
Net interest expense and other	(5,490)	(933)	(767)	(278)	(7,468)
Income (loss) before income taxes	127,342	56,732	50,892	(74,904)	160,062
Provision (benefit) for income taxes	25,571	19,276	12,441	(479)	56,809
Income from continuing operations	101,771	37,456	38,451	(74,425)	103,253
Discontinued operations, net of tax	(424)	—	10,260	—	9,836
Net income (loss) applicable to Helix	101,347	37,456	48,711	(74,425)	113,089
Less:net income applicable to noncontrolling interests	—	—	—	(12,620)	(12,620)
Preferred stock dividends	(250)	—	—	—	(250)
Net income (loss) applicable to Helix common shareholders	$101,097	$37,456	$ 48,711	$ (87,045)	$ 100,219

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

	Six Months Ended June 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$54,692	$355,970	$ 145,058	$ (54,888)	$ 500,832
Cost of sales	31,492	457,199	122,302	(41,199)	569,794
Gross profit (loss)	23,200	(101,229)	22,756	(13,689)	(68,962)
Gain on oil & gas derivative contracts	—	2,482	—	—	2,482
Gain on sale of assets	—	287	5,946	—	6,233
Selling and administrative expenses	(37,458)	(17,915)	(10,576)	902	(65,047)
Income (loss) from operations	(14,258)	(116,375)	18,126	(12,787)	(125,294)
Equity in earnings of investments	(64,736)	3,105	6,711	61,631	6,711
Net interest expense and other	(22,681)	(12,568)	(8,126)	—	(43,375)
Income (loss) before income taxes	(101,675)	(125,838)	16,711	48,844	(161,958)
Provision (benefit) for income taxes	(6,668)	(45,136)	(3,650)	(4,473)	(59,927)
Income from continuing operations	(95,007)	(80,702)	20,361	53,317	(102,031)
Discontinued operations, net of tax	(27)	—	(17)	—	(44)
Net income (loss) applicable to Helix	(95,034)	(80,702)	20,344	53,317	(102,075)
Less:net income applicable to noncontrolling interests	—	—	—	(1,273)	(1,273)
Preferred stock dividends	(94)	—	—	—	(94)
Net income (loss) applicable to Helix common shareholders	$(95,128)	$(80,702)	$ 20,344	$ 52,044	$ (103,442)

	Six Months Ended June 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$189,988	$412,731	$ 517,182	$ (54,287)	$ 1,065,614
Cost of sales	142,352	267,825	409,262	(50,791)	768,648
Gross profit	47,636	144,906	107,920	(3,496)	296,966
Gain on oil & gas derivative contracts	—	78,730	—	—	78,730
Gain on sale of assets	—	1,773	—	—	1,773
Selling and administrative expenses	(24,630)	(15,880)	(42,574)	2,359	(80,725)
Income (loss) from operations	23,006	209,529	65,346	(1,137)	296,744
Equity in earnings of investments	180,826	(2,162)	14,128	(179,025)	13,767
Gain on sale of Cal Dive common stock	59,442	—	—	—	59,442

Net interest expense and other	(14,609)	(6,115)	(7,952)	(987)	(29,663)
Income (loss) before income taxes	248,665	201,252	71,522	(181,149)	340,290
Provision (benefit) for income taxes	36,562	69,622	16,413	(869)	121,728
Income from continuing operations	212,103	131,630	55,109	(180,280)	218,562
Discontinued operations, net of tax	(2,816)	—	10,098	—	7,282
Net income (loss) applicable to Helix	209,287	131,630	65,207	(180,280)	225,844
Less:net income applicable to noncontrolling interests	—	—	—	(18,173)	(18,173)
Preferred stock dividends	(563)	—	—	—	(563)
Preferred stock beneficial conversion charges	(53,439)	—	—	—	(53,439)
Net income (loss) applicable to Helix common shareholders	$155,285	$131,630	$ 65,207	$ (198,453)	$ 153,669

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

	Six Months Ended June 30, 2010				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income (loss), including noncontrolling interests	$ (95,034)	$ (80,702)	$ 20,344	$ 53,317	$ (102,075)
Adjustments to reconcile net income (loss), including noncontrolling interests to net cash provided by (used in) operating activities:					
Equity in earnings of affiliates	64,736	(3,105)	—	(61,631)	—
Other adjustments	17,776	243,919	(13,057)	(10,119)	238,519
Cash provided by (used in) continuing operations	(12,522)	160,112	7,287	(18,433)	136,444
Cash provided by (used in) discontinued operations	—	—	(44)	—	(44)
Net cash provided by (used in) operating activities	(12,522)	160,112	7,243	(18,433)	136,400
Cash flows from investing activities:					
Capital expenditures	(47,963)	(80,203)	(7,446)	—	(135,612)
Distributions from equity investments, net	—	—	1,825	—	1,825
Insurance recovery	7,020	9,086	—	—	16,106
Other	—	109	—	—	109
Net cash used in investing activities	(40,943)	(71,008)	(5,621)	—	(117,572)
Cash flows from financing activities:					
Repayments of debt	(2,163)	—	(2,403)	—	(4,566)
Deferred financing costs	(2,792)	—	—	—	(2,792)

Preferred stock dividends paid and other	69	—	(1,167)	—	(1,098)
Repurchase of common stock	(9,127)	—	—		(9,127)
Excess tax benefit from stock-based compensation	(2,163)	—	—	—	(2,163)
Intercompany financing	62,654	(86,591)	5,504	18,433	—
Net cash provided by (used in) financing activities	46,478	(86,591)	1,934	18,433	(19,746)
Effect of exchange rate changes on cash and cash equivalents	—	—	246	—	246
Net increase (decrease) in cash and cash equivalents	(6,987)	2,513	3,802	—	(672)
Cash and cash equivalents:					
Balance, beginning of year	258,742	2,522	9,409	—	270,673
Balance, end of period	$251,755	$ 5,035	$ 13,211	$ —	$ 270,001

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

	Six Months Ended June 30, 2009				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income, including noncontrolling interests	$ 209,287	$ 131,630	$ 65,207	$ (180,280)	$ 225,844
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates	—	—	(4,058)	361	(3,697)
Equity in earnings of affiliates	(180,826)	2,162	—	178,664	—
Other adjustments	10,172	132,121	(132,954)	197,507	206,846
Cash provided by (used in) operating activities	38,633	265,913	(71,805)	196,252	428,993
Cash provided by discontinued operations	—	—	(6,121)	—	(6,121)
Net cash provided by (used in) operating activities	38,633	265,913	(77,926)	196,252	422,872
Cash flows from investing activities:					
Capital expenditures	(12,303)	(117,238)	(108,861)	—	(238,402)
Investments in equity investments	—	—	(454)	—	(454)
Distributions from equity investments, net	—	—	3,253	—	3,253
Proceeds from sale of Cal Dive common stock	282,656	—	(112,995)	(86,000)	83,661
Proceeds from sales of property	—	23,238	—	—	23,238
Other	—	(15)	—	—	(15)
Cash provided by (used in) investing activities	270,353	(94,015)	(219,057)	(86,000)	(128,719)
Cash provided by discontinued operations	—	—	20,874	—	20,874
	270,353	(94,015)	(198,183)	(86,000)	(107,845)

Net cash used in investing activities					
Cash flows from financing activities:					
Borrowings on revolver	—	—	100,000	—	100,000
Repayments on revolver	(349,500)	—	—	—	(349,500)
Repayments of debt	(2,163)	—	(22,081)	—	(24,244)
Deferred financing costs	(28)	—	—	—	(28)
Preferred stock dividends paid	(500)	—	—		(500)
Repurchase of common stock	(753)	—	(86,000)	86,000	(753)
Excess tax benefit from stock-based compensation	(754)	—	—	—	(754)
Exercise of stock options, net					—
Intercompany financing	141,528	(174,436)	229,160	(196,252)	—
Net cash provided by (used in) financing activities	(212,170)	(174,436)	221,079	(110,252)	(275,779)
Effect of exchange rate changes on cash and cash equivalents	—	—	(931)	—	(931)
Net increase (decrease) in cash and cash equivalents	96,816	(2,538)	(55,961)	—	38,317
Cash and cash equivalents:					
Balance, beginning of year	148,704	4,983	69,926	—	223,613
Balance, end of period	$ 245,520	$ 2,445	$ 13,965	$ —	$ 261,930

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

FORWARD-LOOKING STATEMENTS AND ASSUMPTIONS

This Quarterly Report on Form 10-Q contains various statements that contain forward-looking information regarding Helix Energy Solutions Group, Inc. and represent our expectations and beliefs concerning future events. This forward looking information is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995 as set forth in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, included herein or incorporated herein by reference, that are predictive in nature, that depend upon or refer to future events or conditions, or that use terms and phrases such as "achieve," "anticipate," "believe," "estimate," "expect," "forecast," "plan," "project," "propose," "strategy," "predict," "envision," "hope," "intend," "will," "continue," "may," "potent and similar terms and phrases are forward-looking statements. Included in forward-looking statements are, among other things:

- statements regarding our business strategy, including the potential sale of assets and/or other investments in our subsidiaries and facilities, or any other business plans, forecasts or objectives, any or all of which is subject to change;
- statements regarding our anticipated production volumes, results of exploration, exploitation, development, acquisition or operations expenditures, and current or prospective reserve levels with respect to any oil and gas property or well;
- statements related to commodity prices for oil and gas or with respect to the supply of and demand for oil and gas;
- statements relating to our proposed acquisition, exploration, development and/or production of oil and gas properties, prospects or other interests and any anticipated costs related thereto;
- statements related to environmental risks, exploration and development risks, or drilling and operating risks;
- statements relating to the construction or acquisition of vessels or equipment and any anticipated costs related thereto;
- statements that our proposed vessels, when completed, will have certain characteristics or the effectiveness of such characteristics;
- statements regarding projections of revenues, gross margin, expenses, earnings or losses, working capital or other financial items;
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements regarding any SEC or other governmental or regulatory inquiry or investigation;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we do business;
- statements related to our ability to retain key members of our senior management and key employees;

- statements related to the underlying assumptions related to any projection or forward-looking statement; and
- any other statements that relate to non-historical or future information.

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

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- impact of the weak economic conditions and the future impact of such conditions on the oil and gas industry and the demand for our services;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- the geographic concentration of our oil and gas operations;
- uncertainties regarding our ability to replace depletion;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations and the cyclical nature of the oil and gas industry;
- the effects of indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt and could have other adverse consequences to us;
- the effectiveness of our derivative activities;
- the results of our continuing efforts to control or reduce costs, and improve performance;
- the success of our risk management activities;
- the effects of competition;
- the availability (or lack thereof) of capital (including any financing) to fund our business strategy and/or operations and the terms of any such financing;
- the impact of current and future laws and governmental regulations including tax and accounting developments;
- the effect of adverse weather conditions or other risks associated with marine operations;
- the effect of environmental liabilities that are not covered by an effective indemnity or insurance;
- the potential impact of a loss of one or more key employees; and
- the impact of general, market, industry or business conditions.

Our actual results could differ materially from those anticipated in any forward-looking statements as a result of a variety of factors, including those described in Part II - Item 1A. "Risk Factors" located elsewhere in this Quarterly Report on Form 10-Q and in Item 1A "Risk Factors" in our 2009 Annual Report on Form 10-K ("2009 Form 10-K"). All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

EXECUTIVE SUMMARY

Our Business

We are an international offshore energy company that provides reservoir development solutions and other contracting services to the energy market as well as to our own oil and gas properties. Our oil and gas business is a prospect generation, exploration, development and production company. Employing our own key services and methodologies, we seek to lower finding and development costs relative to industry norms.

Our Strategy

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

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

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

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

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

Demand for our contracting services operations is primarily influenced by the condition of the oil and gas industry, and in particular, the willingness of oil and gas companies to make capital expenditures for offshore exploration, drilling and production operations. Generally, spending for our contracting services fluctuates directly with the direction of oil and natural gas prices. The performance of our oil and gas operations is also largely dependent on the prevailing market prices for oil and natural gas, which are impacted by global economic conditions, hydrocarbon production and excess capacity, geopolitical issues, weather and several other factors.

Economic Outlook and Industry Influences

Although there have been some indicators that the U.S and global economies are stabilizing from the significant downturn experienced since late 2008, there remains a general weakness in the equity and credit capital markets that continues to generate a certain degree of uncertainty regarding the overall outlook of the global economy. Generally, the economic downturn has affected us through decreases in prices of both oil and natural gas. The decreases in oil and natural gas prices not only negatively affected the amount of revenues we received from the sale of our own production of these commodities but also reduced the demand for our Contracting Services as some oil and gas companies curtailed their capital spending. The demand for our Contracting Services began to soften around mid-year 2009 and this weakening resulted in lower utilization for our Contracting Services assets and reduced margins for many of the services we perform. As a result, we initiated efforts to accelerate some of our internal projects to augment production from our oil and gas properties, which affected our operating results in the first half of 2010, more specifically our first-quarter 2010 operating results. Most of our planned internal work for 2010 has now been completed.

Oil prices have averaged approximately $75 per barrel in 2010, which is higher than prices realized in late 2008 and the first half of 2009. Natural gas prices continue to range between approximately $4.00 and $5.00 per thousand cubic feet (Mcf) of gas, which remains towards the lower end of prices realized over the past five years but slightly higher than amounts realized in the first half of 2009. We believe that the stabilization in price for both oil and natural gas are contributing to increased energy services capital spending especially in regions outside the Gulf of Mexico (discussed below), which in turn could result in additional work opportunities for our Contracting Services business over the remainder of 2010.

In April 2010, an explosion occurred on the Deepwater Horizon drilling rig located on the site of the Macondo well at Mississippi Canyon Block 252 (Note 2). The resulting events included loss of life, the complete destruction of the drilling rig and an oil spill, the magnitude of which is unprecedented in U.S territorial waters. In May 2010, the U.S. Department of Interior ("DOI") announced a total moratorium on new drilling in the Gulf of Mexico. This moratorium also affected 33 in progress wells in the deepwater. The moratorium on drilling in the shallow water of the Gulf, as defined as water depths less than 500 feet, was lifted in late May 2010. However, the DOI extended the drilling moratorium on deepwater wells through November 2010. The drilling moratorium was challenged in court and the court enjoined its enforcement. However, the DOI has recently amended its original drilling moratorium which remains in effect at the time of this filing despite additional potential legal challenges.

While we do not have any plans to drill any additional deepwater wells during the proposed period covered by the existing drilling moratorium, our contracting services businesses rely heavily on the industry investment in the Gulf of Mexico and any prolonged moratorium could adversely affect our future results of operations and financial position. Although our current contracting services activities remain substantially unaffected, any extension of the current drilling moratorium may result in a deferral or cancellation of portions of our contracted backlog or may decrease opportunities for future contracts for work in the Gulf of Mexico. Furthermore, a long-term cessation of deepwater drilling in the Gulf of Mexico could require us to relocate portions of our fleet to other international locations, such as the North Sea, West Africa, Southeast Asia, Brazil and Mexico.

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

At June 30, 2010, we had cash on hand of $270.0 million and $377.4 million available for borrowing under our Revolving Credit Facilities. To stabilize the price we receive for our oil and natural gas production we have hedged a substantial portion of our anticipated remaining 2010 production. Our capital expenditures for full year 2010 are expected to total approximately $190 million, which reflects the final construction payments for our Well Enhancer, Caesar and Helix Producer I ("HP I") vessels and the completion of two of our significant deepwater oil and gas properties expected to commence production in 2010 (one achieved first production in February 2010 and the other's initial production is expected late in the third quarter of 2010). If we successfully implement our business plan, we believe we have sufficient liquidity without incurring additional indebtedness beyond the existing capacity under the Revolving Credit Facility.

Our business is substantially dependent upon the condition of the oil and natural gas industry and, in particular, the willingness of oil and natural gas companies to make capital expenditures for offshore exploration, drilling and production operations. The level of capital expenditures generally depends on the prevailing views of future oil and natural gas prices, which are influenced by numerous factors, including but not limited to:

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

- the ability of oil and natural gas companies to generate funds or otherwise obtain external capital for exploration, development and production operations;
- the sale and expiration dates of offshore leases in the United States and overseas;
- technological advances affecting energy exploration production transportation and consumption;
- weather conditions;
- environmental and other governmental regulations; and
- tax policies.

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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 two continuing reportable segments in accordance with FASB Codification ("ASC") Topic No. 280 Segment Reporting. As a result, our reportable segments consist of the following: Contracting Services, Oil and Gas and Production Facilities. Formerly, we had a third contracting services segment, Shelf Contracting. In June 2009, we ceased consolidating our Shelf Contracting segment, which represented the results and operations of Cal Dive, following the sale of a substantial amount of our ownership of Cal Dive (Note 4). Each line item within our consolidated statement of operations for the three and six month periods ended June 30, 2010 is impacted significantly when compared to the same periods last year as a result of the deconsolidation of the Cal Dive results. We continued to disclose the operating results of the Shelf Contracting business as a segment through June 10, 2009. See Note 4 elsewhere in this Quarterly Report on Form 10-Q and Note 3 of our 2009 Form 10-K for additional disclosure regarding our transactions that substantially eliminated our ownership interest in Cal Dive.

All material intercompany transactions between the segments have been eliminated in our consolidated financial statements.

Contracting Services Operations

We seek to provide services and methodologies that we believe are critical to finding and developing offshore reservoirs and maximizing production economics. The Contracting Services segment includes operations such as subsea construction, well operations, robotics and production facilities. Our Contracting Services business operates primarily in the Gulf of Mexico, the North Sea, Asia Pacific and West Africa regions, with services that cover the lifecycle of an offshore oil or gas field. As of June 30, 2010, our Contracting Services operations had backlog of approximately $413 million, including $328 million for 2010, which included amounts for the HP I and the Caesar that were placed in service during the second quarter of 2010. At December 31, 2009, our Contracting Services backlog totaled approximately $251 million, including $217 million for 2010. These backlog contracts are cancellable without penalty in many cases. Backlog is not a reliable indicator of total annual revenue for our Contracting Services businesses as contracts may be added, cancelled and in many cases modified while in progress.

Oil and Gas Operations

We began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization of our contracting services business and to generate incremental returns. We 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 have been 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.

Mid Year Reserve Assessment

In connection with the regular mid-year review as well as our efforts to pursue potential divestment alternatives for our oil and gas assets, we engaged an independent petroleum reservoir engineering firm to update our estimates of proved reserves for our domestic oil and gas properties as of June 30, 2010. The resulting independent petroleum engineer reserve report indicated the we had a significant reduction in proved reserves (approximately 143 Bcfe from year end 2009) resulting from a combination of factors including well performance issues at certain of our producing fields, most notably our Bushwood field at Garden Banks Blocks 462/463/506/507, as well as changes in the field economics of some of our other oil and gas properties. The changes in field economics primarily affected properties that were either close to the end of their production life or in which we had proved undeveloped reserves, which would have been required to be developed in the near term The decision not to develop these properties in light of these economic changes was also driven by our desire to pursue potential alternatives to divest our oil and gas assets and the increasing uncertainties about future oil and gas operations in the Gulf of Mexico as a result of the oil spill from the Macondo well. As a result of the reduction in estimated reserves we were required to record oil and gas property impairment charges of $159.9 million at June 30, 2010.

The total present value of the future cash flows of our estimated proved reserves at June 30, 2010 as discounted by the SEC mandated 10% discount was approximately $1.3 billion, which is substantially the same amount we reported at December 31, 2009 (see Note 20 of our 2009 Annual Report on Form 10-K). The reason for the relative lack of change in our future cash flows despite the rather substantial reduction in estimated proved reserves can be primarily attributed to the higher natural gas and oil prices used at June 30, 2010 as compared to those used at December 31, 2009 (see table below) and the reduction of some or all of the future development costs associated with projects that we have now concluded do not merit future development because of updated economics.

Six Months Ended June 30, 2010— (1)		
Oil price per Bbl	$	73.15
Natural gas price per Mcf	$	4.07
Year Ended December 31, 2009—(1)		
Oil price per Bbl	$	58.05
Natural gas price per Mcf	$	3.72

(1) Price at June 30, 2010 and December 31, 2009 represents the average trailing twelve month price for both oil and natural gas as now required under the new accounting standards.

Impairments

Following the determination of a significant reduction in our estimates of reserves at June 30, 2010, we recorded oil and gas property impairment charges totaling $159.9 million in the second quarter of 2010 which affected the carrying value of 15 of our Gulf of Mexico oil and gas properties. The Bushwood field was not impaired; however, we revised our depletion rate for the field, which substantially increase resulted in an incremental $18.8 million of depletion expense being recorded in the second quarter compared to what would have been recorded had there been no change in the Bushwood field's estimated proved reserves at June 30, 2010. See Note 6 for more information regarding our impairment charges recorded in the first half of 2010 and 2009.

Discontinued Operations

In April 2009, we sold Helix RDS Limited to a subsidiary of Baker Hughes Incorporated for
$25 million. Helix RDS is a provider of reservoir engineering, geophysical, production technology and associated specialized consulting services to the upstream oil and gas industry. We have presented the results of Helix RDS as

discontinued operations in the accompanying condensed consolidated financial statements (Note 2). Helix RDS was previously a component of our Contracting Services business.

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Comparison of Three Months Ended June 30, 2010 and 2009

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 202,317	$ 239,476	$ (37,159)
Shelf Contracting		197,656	(197,656)
Oil and Gas	102,586	89,992	12,594
Production Facilities	21,391	1,120	20,271
Intercompany elimination	(27,032)	(33,605)	6,573
	$ 299,262	$ 494,639	$ (195,377)
Gross profit (loss) (in thousands) –			
Contracting Services	$ 50,333	$ 41,364	$ 8,969
Shelf Contracting		53,923	(53,923)
Oil and Gas	(151,368)	43,611	(194,979)
Production Facilities	13,078	(859)	13,937
Corporate	(747)	(652)	(95)
Intercompany elimination	(6,114)	(1,631)	(4,483)
	$ (94,818)	$ 135,756	$ (230,574)
Gross Margin –			
Contracting Services	25%	17%	8 pts
Shelf Contracting	%	27%	N/A
Oil and Gas	(148)%	48%	(196) pts
Total company	(32)%	27%	(59) pts
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	10/74%	9/88%	
Well operations	3/98%	2/98%	
ROVs	46/61%	47/72%	
Shelf Contracting	N/A	N/A	

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates and vessels taken out of service prior to their disposition.
(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues during the three month periods ended June 30, 2010 and 2009 were as follows (in thousands):

Three Months Ended

	June 30, 2010	2009	Increase/ (Decrease)
Contracting Services	$ 24,426	$ 28,951	$ (4,525)
Production Facilities	2,606		2,606
Shelf Contracting		4,654	(4,654)
	$ 27,032	$ 33,605	$ (6,573)

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Intercompany segment profit during the three month periods ended June 30, 2010 and 2009 was as follows (in thousands):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase/ (Decrease)
Contracting Services	$ 3,701	$ 1,551	$ 2,150
Production Facilities	2,413	(29)	2,442
Shelf Contracting		109	(109)
	$ 6,114	$ 1,631	$ 4,483

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	790	806	(16)
Oil sales revenue (in thousands)	$ 57,366	$ 58,264	$ (898)
Average oil sales price per Bbl (excluding hedges)	$ 75.39	$ 68.40	$ 6.99
Average realized oil price per Bbl (including hedges)	$ 72.59	$ 72.29	$ 0.30
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 239		
Change in production volume (in thousands)	(1,137)		
Total decrease in oil sales revenue (in thousands)	$ (898)		
Gas production volume (MMcf)	7,147	7,535	(388)
Gas sales revenue (in thousands)	$ 43,591	$ 31,737	$ 11,854
Average gas sales price per mcf (excluding hedges)	$ 4.44	$ 3.80	$ 0.64
Average realized gas price per mcf (including hedges)	$ 6.10	$ 4.21	$ 1.89
Increase in gas sales revenue due to:			
Change in prices (in thousands)	$ 14,221		
Change in production volume (in thousands)	(2,367)		
Total increase in gas sales revenue (in thousands)	$ 11,854		
Total production (MMcfe)	11,889	12,371	(482)
Price per Mcfe	$ 8.49	$ 7.28	$ 1.21

Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 100,957	$ 90,002	$ 10,955
Other revenues(1)	1,629	(10)	1,639
	$ 102,586	$ 89,992	$ 12,594

(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 converted to Mcfe at a ratio of one barrel of oil to six Mcf:

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	Three Months Ended June 30,			
	2010		2009	
	Total	Per Mcfe	Total	Per Mcfe
	(in thousands, except per Mcfe amounts)			
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$15,763	$1.33	$17,867	$1.44
Workover	3,504	0.29	915	0.07
Transportation	1,036	0.09	2,183	0.18
Repairs and maintenance	1,730	0.15	2,402	0.19
Overhead and company labor	1,579	0.13	2,866	0.23
	$23,612	$1.99	$26,233	$2.11
Depletion expense (3)	$63,330	$5.33	$41,182	$3.33
Abandonment	401	0.03	786	0.06
Accretion expense	4,012	0.34	4,059	0.33
Net hurricane costs (reimbursements)	1,563	0.13	(38,809)	(3.14)
Impairment	159,862	13.45	11,446	0.93
	229,168	19.28	18,664	1.51
Total	$252,780	$21.27	$44,897	$3.62

(1) Excludes exploration expense of $1.2 million and $1.5 million for the three month periods ended June 30, 2010 and 2009, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Includes an incremental $18.8 million related to our Bushwood field following reductions in our estimated proved reserves at June 30, 2010 (Note 6).

The following table contains selected data extracted from our condensed consolidated statements of operations. This information is presented to illustrate the amounts associated with our Contracting Services and Oil and Gas businesses to facilitate the understanding of the variances in our results of operations for the comparative three-month periods ended June 30, 2010 and 2009:

	2010			2009		
	Contracting Services	Oil and Gas	Total	Contracting Services	Oil and Gas	Total
	(in thousands)					
Revenues	$ 196,676	$ 102,586	$299,262	$ 404,647	$ 89,992	$ 494,639
Gross profit (loss)	56,550	(151,368)	(94,818)	92,145	43,611	135,756
Gain on sale or acquisition of assets	-	(14)	(14)	70	1,249	1,319
Selling and administrative expenses	18,503	6,043	24,546	33,336	6,036	39,372
Equity in earnings of investment	1,656	-	1,656	6,264	-	6,264
Net interest expense and other	18,277	3,905	22,182	2,383	5,085	7,468

The following table modifies the preceding table to illustrate the effect that our former Shelf Contracting business (Cal Dive) had on our Contracting Services operating results in the second quarter of 2009 (Note 4). These results are provided to facilitate the understanding of the variances discussed below of our Contracting Services operations as reported on an continuing basis for the comparative three month periods ended June 30, 2009 and 2010 (amounts in thousands):

	2009			2010	
	Contracting Services as reported	Less Shelf Contracting	Continuing Contracting Services (in thousands)	Contracting Services	Variance Of Continuing Contracting Services
Revenues	$ 404,647	$ 197,656	$ 206,991	$ 196,676	$ (10,315)
Gross Profit	92,145	53,923	38,222	56,550	18,328
Gain on sale or acquisition of assets	70	-	70	-	(70)
Selling and administrative expenses	33,336	15,778	17,558	18,503	945
Equity in earnings of investment	6,264	896	5,368	1,656	(3,712)
Net interest expense and other	2,383	3,466	(1,083)	18,277	19,360

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

Revenues. Our Contracting Services revenues decreased 5% for the three month period ended June 30, 2010 compared to the same period in 2009 reflecting lower utilization of our construction vessels and ROVs partially offset by the addition of three vessels to our fleet, including the Caesar being placed in service in May 2010. Separately, in the 2009 period we had significant revenues associated with a large international construction project for which we completed our scope of work in the third quarter of 2009. Our second quarter 2010 revenues included amounts earned by the contracting of the Q4000, the Express and the HPI to assist in the Gulf oil spill response and containment efforts. These vessels remain on site as of the time of this filing.

Oil and Gas revenues increased 14% during the three month period ended June 30, 2010 as compared to the same period in 2009. The increase in revenues is attributable to higher prices received for our natural gas and oil sales volumes, in particular our natural gas sales realization price which increased by 45%. Our production was down 0.5 billion cubic feet of natural gas equivalent (Bcfe) in the second quarter of 2010 as compared to the same period in 2009. Increases in production from our deepwater properties were more than offset by the reduction in production from our shelf properties. For the month of July our production rate approximated 110 MMcfe/d as compared to an approximate average of 131 MMcfe/d in the second quarter of 2010.

Gross Profit. Our Contracting Services gross profit increased by 48% primarily reflecting our scope of work in the Gulf oil spill response efforts coupled with the relatively low margin that our large international construction project earned in the prior year.

The Oil and Gas gross profit in second quarter 2010 included non cash impairment charges totaling $159.9 million as previously discussed in “Oil and Gas Operations” above. During the second quarter of 2009, our oil and gas operating results included $63.1 million of oil and gas property impairments. After adjusting for these impairment charges, our oil and gas operating gross profit for the three month period ended June 30, 2010 decreased by $98.2 million as compared to the same period in 2009. The decrease is substantially attributed to the settlement of our insurance claim in June 2009, where we received approximately $100 million to settle all our Hurricane Ike related claims (Note 6).

Selling and Administrative Expenses. Selling and administrative expenses of $24.5 million for the second quarter of 2010 were $1.0 million higher than the $23.6 million incurred in the same prior year period after excluding our Shelf Contracting expense. The increase primarily reflects higher legal fees and certain costs related to our pursuit of potential alternatives to divest our oil and gas business.

Equity in Earnings of Investments. Equity in earnings of investments decreased by $4.6 million during the three month period ended June 30, 2010 as compared to the same prior year period. This decrease was primarily due to $4.3 million of losses related to the start-up costs for the CloughHelix JV in Australia (Note 8).

Net Interest Expense. Our net interest expense was $20.5 million in second quarter 2010 as compared to $15.6 million in the same prior year period. Gross interest expense of $24.6 million during the three month period ended June 30, 2010 was lower than the $27.7 million incurred in 2009 reflecting both lower interest rates and lower balances outstanding as well as inclusion of $2.8 million of interest related to Cal Dive’s debt that was deconsolidated in June 2009. Capitalized interest totaled $3.9 million for the three month period ended June 30, 2010 compared with $11.9 million for the same period last year. The decrease in our capitalized interest was primarily attributable to the completion of our major capital projects since mid year 2009, including placing the Caesar and HP I vessels in service during the second quarter of 2010. Interest income totaled $0.2 million for the three month period ended June

30, 2010 compared with $0.1 million in the comparable period in 2009.

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Other Income (Expense). We incurred foreign exchange losses related to declines in our non U.S dollar functional currencies and currency contracts totaling $1.7 million in the second quarter of 2010 compared to gains of $8.9 million in second quarter of 2009. The losses on our foreign exchange forward contracts totaled $0.4 million in the second quarter of 2010 compared to a gain of $4.5 million in the second quarter of 2009 (Note 18).

Provision for Income Taxes. Income taxes reflect a benefit of $52.4 million in the second quarter of 2010 as compared to income tax expense of $56.8 million in the same prior year period. The variance primarily reflects decreased profitability in the current year period and the deconsolidation of CDI in 2009. The effective tax rate for the second quarter of 2010 was a benefit of 38.1% due to increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions. The effective tax rate for the second quarter of 2009 was an expense of 35.5% as a result of the consolidation of CDI in 2009.

Comparison of Six Months Ended June 30, 2010 and 2009

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

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Increase/ (Decrease)
Revenues (in thousands) –			
Contracting Services	$ 356,517	$ 470,331	$ (113,814)
Shelf Contracting		404,709	(404,709)
Oil and Gas	193,301	250,173	(56,872)
Production Facilities	22,711	1,120	21,591
Intercompany elimination	(71,697)	(60,719)	(10,978)
	$ 500,832	$ 1,065,614	$ (564,782)
Gross profit (loss) (in thousands) –			
Contracting Services	$ 87,955	$ 88,617	$ (662)
Shelf Contracting		92,728	(92,728)
Oil and Gas	(150,119)	119,725	(269,844)
Production Facilities	13,099	(859)	13,958
Corporate	(1,461)	(1,324)	(137)
Intercompany elimination	(18,436)	(1,921)	(16,515)
	$ (68,962)	$ 296,966	$ (365,928)
Gross Margin –			
Contracting Services	25%	19%	6 pts
Shelf Contracting		23%	N/A
Oil and Gas	(78)%	48%	(126) pts
Total company	(14)%	28%	(42) pts
Number of vessels(1)/ Utilization(2) –			
Contracting Services:			
Construction vessels	10/78%	9/83%	
Well operations	3/79%	2/87%	
ROVs	46/60%	47/68%	

Shelf Contracting	N/A	N/A

(1) Represents number of vessels as of the end of the period excluding acquired vessels prior to their in-service dates and vessels taken out of service prior to their disposition.
(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues during the six month periods ended June 30, 2010 and 2009 were as follows (in thousands):

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	Six Months Ended June 30, 2010	2009	Increase/ (Decrease)
Contracting Services	$68,167	$52,854	$15,313
Production Facilities	3,530		3,530
Shelf Contracting		7,865	(7,865)
	$71,697	$60,719	$10,978

Intercompany segment profit during the six month periods ended June 30, 2010 and 2009 was as follows (in thousands):

	Six Months Ended June 30, 2010	2009	Increase/ (Decrease)
Contracting Services	$ 15,143	$ 1,447	$ 13,696
Production Facilities	3,293	(29)	3,322
Shelf Contracting		503	(503)
	$ 18,436	$ 1,921	$ 16,515

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

	Six Months Ended June 30, 2010	2009	Increase/ (Decrease)
Oil and Gas information–			
Oil production volume (MBbls)	1,445	1,626	(181)
Oil sales revenue (in thousands)	$ 104,374	$ 105,655	$ (1,281)
Average oil sales price per Bbl (excluding hedges)	$ 75.53	$ 60.00	$ 15.53
Average realized oil price per Bbl (including hedges)	$ 72.24	$ 64.99	$ 7.25
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 11,778		
Change in production volume (in thousands)	(13,059)		
Total decrease in oil sales revenue (in thousands)	$ (1,281)		
Gas production volume (MMcf)	14,490	14,525	(35)
Gas sales revenue (in thousands)	$ 85,775	$ 69,168	$ 16,607
	$ 4.87	$ 4.23	$ 0.64

Average gas sales price per mcf (excluding hedges)			
Average realized gas price per mcf (including hedges)	$ 5.92	$ 4.76	$ 1.16
Increase in gas sales revenue due to:			
Change in prices (in thousands)	$ 16,816		
Change in production volume (in thousands)	(209)		
Total increase in gas sales revenue (in thousands)	$ 16,607		
Total production (MMcfe)	23,159	24,279	(1,120)
Price per Mcfe	$ 8.21	$ 7.20	$ 1.01
Oil and Gas revenue information (in thousands)–			
Oil and gas sales revenue	$ 190,149	$ 174,823	$ 15,326
Other revenues(1)	3,152	75,350	(72,198)
	$ 193,301	$ 250,173	$ (56,872)

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

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

	Six Months Ended June 30,			
	2010		2009	
	Total	Per Mcfe	Total	Per Mcfe
	(in thousands, except per Mcfe amounts)			
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$30,321	$1.31	$36,467	$1.50
Workover	15,117	0.65	1,695	0.07
Transportation	2,329	0.10	3,421	0.14
Repairs and maintenance	3,532	0.15	5,185	0.21
Overhead and company labor	3,473	0.15	4,361	0.18
	$54,772	$2.36	$51,129	$2.10
Depletion expense(3)	$103,607	$4.47	$85,162	$3.51
Abandonment	1,166	0.05	1,531	0.06
Accretion expense	7,943	0.34	8,062	0.33
Net hurricane costs (reimbursements)	3,618	0.16	(29,200)	(1.20)
Impairment	170,974	7.38	11,804	0.49
	287,308	12.40	77,359	3.19
Total	$342,080	$14.76	$128,488	$5.29

(1) Excludes exploration expense of $1.3 million and $2.0 million for the six months ended June 30, 2010 and 2009, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

(3) Includes an incremental $18.8 million related to our Bushwood field following reductions in our estimated proved reserves at June 30, 2010 (Note 6).

The following table contains selected data extracted from our condensed consolidated statements of operations. This information is presented to illustrate the amounts associated with our Contracting Services and Oil and Gas businesses and to facilitate the understanding of the variances in our results of operations for the comparative six-month periods ended June 30, 2010 and 2009:

	2010			2009		
	Contracting Services	Oil and Gas	Total	Contracting Services	Oil and Gas	Total
	(in thousands)					
Revenues	$ 307,531	193,301	500,832	$ 815,441	$ 250,173	$ 1,065,614
Gross profit (loss)	81,157	(150,119)	(68,962)	177,241	119,725	296,966
Gain on sale or acquisition of assets	-	6,233	6,233	70	1,703	1,773
Selling and administrative expenses	50,844	14,203	65,047	68,695	12,030	80,725
Equity in earnings of investment	6,711	-	6,711	13,767	-	13,767
	34,479	8,896	43,375	18,903	10,760	29,663

Net interest expense and other	

The following table modifies the preceding table to illustrate the effect that our former Shelf Contracting business (Cal Dive) had on our Contracting Services operating results over the first half of 2009 (Note 4).   These results are provided to facilitate the understanding of the variances discussed below of our Contracting Services operations as reported on an continuing basis for the comparative six month periods ended June 30, 2009 and 2010 (amounts in thousands):

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	2009			2010	
	Contracting Services as reported	Less Shelf Contracting	Continuing Contracting Services (in thousands)	Contracting Services	Variance Of Continuing Contracting Services
Revenues	$ 815,441	$ 404,709	$ 410,732	$ 307,531	(103,201)
Gross Profit	177,241	92,728	84,513	81,157	(3,356)
Gain on sale or acquisition of assets	70	-	70	-	(70)
Selling and administrative expenses	68,695	33,651	35,044	50,844	15,800
Equity in earnings of investment	13,767	896	12,871	6,711	(6,160)
Net interest expense and other	18,903	6,642	12,261	34,479	22,218

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

Revenues. Our Contracting Services revenues decreased 25% for the six month period ended June 30, 2010 compared to the same period in 2009 reflecting the increased amount of internal vessel utilization to develop our oil and gas properties in 2010, the scheduled regulatory dry docking of our Seawell vessel in February 2010 and the completion of a large international construction project in the third quarter of 2009. Overall utilization levels for our subsea construction and well operations vessels and ROVs decreased. We have added three vessels to our fleet at June 30, 2010 compared to the fleet count at June 30, 2009, including the Caesar being placed in service in May 2010. As previously noted our Q4000, Express and HP I vessels have all been involved in the Gulf oil spill response. These vessels remain on site at the time of the filing of this Quarterly Report on Form 10-Q.

Oil and Gas revenues decreased 23% during the six month period ended June 30, 2010 as compared to the same period in 2009. The decrease is substantially attributable to the $73.5 million of previously accrued royalty payments that we recognized in the first quarter of 2009 following a favorable judicial ruling in the dispute over the lessee's responsibility to make these payments with respect to the Gunnison leases (Note 6). For additional information regarding the resolution of these previously disputed royalty payments see Note 17 of our 2009 Form 10-K. Excluding the effect of these royalty payments being reversed our oil and gas revenues increased by 9% primarily reflecting higher oil and natural gas prices. Our production was 1.1 Bcfe less for the first half of 2010 as compared to the same period in 2009. Our production in the first half of 2010 benefited from increased production from our Bushwood field, including commencement of production from our Danny oil reservoir in February 2010. This increase in our deepwater production was more than offset by decreases in production from our shelf properties and mechanical platform issues at our East Cameron Block 346 field in the first quarter of 2010, which were resolved in April 2010. We anticipate production from our Phoenix field to commence late in third quarter of 2010. Initial production from this field was delayed when we contracted the HP I to assist in the Gulf oil spill containment efforts.

Gross Profit.   Our Contracting Services gross profit decreased by 4% primarily reflecting the lower vessel utilization and our increased scope of internal work related to the development of our oil and gas properties in the first half of 2010.

The Oil and Gas gross profit decrease of $269.8 million in first half of 2010 as compared to the same period in 2009 was primarily attributable to the reversal of the disputed accrued royalties as discussed above, the insurance settlement agreement in June 2009 (Note 6), higher recorded impairment charges as further discussed below, and increased workover costs mostly attributed to our Bushwood and East Cameron Block 346 fields.

Following the determination of a significant reduction in our estimates of proved reserves at June 30, 2010, we recorded oil and gas property impairment charges totaling $159.9 million in the second quarter of 2010 which affected the carrying value of 15 of our Gulf of Mexico oil and gas properties.   Although our Bushwood field was not impaired, the revised depletion rate for the field increased substantially, which

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resulted in an incremental $18.8 million of depletion expense being recorded in the second quarter as compared to what would have been recorded had there been no change in the Bushwood field's estimated proved reserves at June 30, 2010. Further, following decreases in natural gas prices from those in effect at year end 2009, in the first quarter of 2010 we were required to record $7.0 million of impairment expense related to three of our U.S. Gulf of Mexico natural gas production fields and a $4.1 million impairment related to our only non-domestic (U.K.) oil and gas property. In the second quarter of 2009, we recorded $63.1 million of property impairment primarily related to new estimates of asset retirement obligations related to hurricane damaged properties. See Note 6 for additional information regarding our property impairments.

Gain on Sale or Purchase of Assets, Net. For the six month period ended June 30, 2010 our gain was primarily associated with the acquisition of the remaining 50% working interest related to the Camelot field in the United Kingdom (Note 6). The sales in the first half of 2009 reflected the sale of East Cameron Block 316 for gross proceeds of $18 million ($0.7 million gain) and the remaining 10% of our interest in the Bass Lite field in January 2009.

Selling and Administrative Expenses. Selling and administrative expenses of $65.0 million for the six months ended June 30, 2010 were $18.0 million higher than the $47.1 million incurred in the same prior year period after excluding our Shelf Contracting expense. The increase primarily reflects the $17.5 million related to our settlement of litigation claims in Australia (Note 16).

Equity in Earnings of Investments. Equity in earnings of investments decreased by $7.1 million during the six month period ended June 30, 2010 as compared to the same prior year period. This decrease was mostly due to the start-up costs ($5.7 million) related to the CloughHelix JV in Australia (Note 8). We also processed lower production throughput at both the Deepwater Gateway and Independence Hub facilities in the first half of 2010 as compared to the first half of 2009.

Net Interest Expense. We reported net interest of $36.2 million for the six month period ended June 30, 2010 as compared to $37.6 million in the same prior year period. Gross interest expense of $48.9 million during the six month period ended June 30, 2010 was lower than the $57.5 million incurred in 2009 reflecting both lower interest rates and lower balances outstanding as well as inclusion of $6.5 million of interest related to Cal Dive's debt that was deconsolidated in June 2009. Capitalized interest totaled $12.4 million for the six month period ended June 30, 2010 compared with $19.5 million for the same period last year. The decrease in our capitalized interest was primarily attributable to the completion of our major capital projects since mid year 2009, more specifically during the first half of 2010, including placing in service our Caesar and HP I vessels. Interest income totaled $0.4 million for both the first half of 2010 and the first half of 2009.

Other Income (Expense). We incurred foreign exchange losses related to declines in our non U.S dollar functional currencies and currency contracts totaling $7.2 million for the six month period ended June 30, 2010 compared to gains of $7.7 million for the six month period ended June 30, 2009. Losses on our foreign exchange forward contracts totaled $3.3 million in the first half of 2010 compared gains of $5.1 million for the same period last year (Note 18).

Provision for Income Taxes. Income taxes reflect a benefit of $59.9 million in the six months ended June 30, 2010 as compared to income tax expense of $121.7 million in the same prior year period. The variance primarily reflects decreased profitability in the current year period and the deconsolidation of CDI in 2009. The effective tax rate for the six month period ended June 30, 2010 was a benefit of 37.0% due to increased benefit derived from the effect of lower tax rates in certain foreign jurisdictions. The effective tax rate for the six month period ended June 30, 2009 was an expense of 35.8% as a result of the consolidation of CDI in 2009.

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:

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	June 30, 2010	December 31, 2009
	(in thousands)	
Net working capital	$ 217,523	$ 197,072
Long-term debt(1)	1,347,994	1,348,315

(1) Long-term debt does not include the current maturities portion of the long-term debt as such amount is included in net working capital. It is also net of unamortized debt discount that was recorded effective with the adoption of a new accounting standards effective January 1, 2009 (see Note 2 of 2009 Form 10-K).

The carrying amount of our debt, including current maturities as of June 30, 2010 and December 31, 2009 follow :

	June 30, 2010	December 31, 2009
	(in thousands)	
Term Loan (matures July 2013)	$ 412,603	$ 414,766
Revolving Credit Facility (matures November 2012)		
Convertible Senior Notes (matures March 2025) (1)	277,200	273,064
Senior Unsecured Notes (matures January 2016)	550,000	550,000
MARAD Debt (matures August 2027)	117,050	119,235
Loan Note(2)	2,537	3,674
Total	$ 1,359,390	$ 1,360,739

(1) Net of the unamortized debt discount resulting from adoption of new provisions of ASC Topic No. 470-20 “Convertible Debt and Other Options” on January 1, 2009. The notes will increase to $300 million face amount through accretion of non-cash interest expense through 2012, the date the note can first be put to us (Note 9).
(2) Assumed to be current, represents the loan provided by Kommandor RØMØ to Kommandor LLC (Note 16).

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

	Six Months Ended June 30, 2010	2009
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$ 136,400	$ 422,872
Investing activities	$ (117,572)	$ (107,845)
Financing activities	$ (19,746)	$ (275,779)

As of June 30, 2010, our liquidity totaled $647.4 million, including cash and cash equivalents of $270.0 million and $377.4 million of available borrowing capacity under our Revolving Credit Facility (Note 9).

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

We remain focused on maintaining a strong balance sheet and adequate liquidity. We may reduce planned capital spending and seek further additional dispositions of our non-core business assets. We also have a reasonable basis for estimating our future cash flow supported by our remaining

Contracting Services backlog and the significant hedged portion of our estimated oil and gas production for 2010. We believe that internally generated cash flow and available borrowing capacity under our amended Revolving Credit Facility will be sufficient to fund our operations. In the first half of 2009, we repaid the remaining $349.5 million of borrowing under our revolving credit facility.

In accordance with our Credit Agreement, Senior Unsecured Notes, the Convertible Senior Notes and the MARAD debt, we are required to comply with certain covenants and restrictions, including certain financial ratios (such as collateral coverage, interest coverage, consolidated leverage), the maintenance of minimum net worth and working capital and debt-to-equity requirements. As of June 30, 2010 and December 31, 2009, we were in compliance with all of our debt covenants and restrictions.

The Credit Agreement and Senior Unsecured Notes also contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Credit Agreement does permit us to incur certain unsecured indebtedness, and also provides for our subsidiaries to incur project financing indebtedness (such as our MARAD loans) secured by the underlying asset, provided that the indebtedness is not guaranteed by us. Upon the occurrence of certain dispositions or the issuance or incurrence of certain types of indebtedness, we may be required to prepay a portion of the Term Loan with all or a portion of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any excess will then be applied to the Revolving Loans.

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

The Convertible Senior Notes can be converted prior to the stated maturity under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. No conversion triggers were met during either the first half of 2010 or 2009.

We amended our Credit Agreement in October 2009 and again in February 2010. In October 2009 the Credit Agreement was amended to, among other things, extend its maturity from July 2011 to November 2012. In February 2010, the Credit Agreement was once again amended, to among other things, modify the consolidated leverage ratio test and to include an additional senior secured debt leverage ratio test for periods beginning on or after March 31, 2010. See Note 9 for additional information related to our long-term debt, including more information regarding the recent amendments of our Credit Agreement and our requirements and obligations under the debt agreements including our covenants and collateral security.

Working Capital

Cash flow from operating activities decreased by $286.5 million in the six months ended June 30, 2010 as compared to the same period in 2009. This decrease includes the effect of recognizing $73.5 million of previously disputed cash royalty payments that we had been deferring until January 2009 (Note 6), the deconsolidation of Cal Dive in June 2009 (Note 4), the receipt of insurance proceeds associated with the settlement of our Hurricane Ike claims (Note 6), our increased internal utilization of vessels for developing our oil and gas properties in the first three months of 2010 and a decrease in our working capital cash flows.

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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 six months ended June 30, 2010 and 2009 were as follows:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in thousands)	
Capital expenditures:		
Contracting Services	$ (29,720)	$ (110,986)
Shelf Contracting		(39,569)
Production Facilities(1)	(41,000)	(18,179)
Oil and Gas(1)	(48,786)	(69,668)
Investments in equity investments	(6,307)	(454)
Distributions from equity investments, net(2)	8,132	3,253
Proceeds from sale of properties and other	109	127,758
Cash used in investing activities	$(117,572)	$ (107,845)

(1) Amounts net of insurance recovery ($7.0 million for Production Facilities and $9.1 million for oil and gas). This insurance recovery is related to damages sustained to Phoenix field in 2005 and which we remediated upon our acquisition of the field in 2007.
(2) 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 June 30, 2010 and December 31, 2009, we had $35.5 million and $35.4 million of restricted cash, all of which related to the funds contractually required to be escrowed to cover the asset retirement obligations associated with the South Marsh Island Block 130 field. We have fully satisfied our escrow requirements and may use the restricted cash for the future asset retirement costs for this field. These amounts are reflected in other assets, net in the accompanying condensed consolidated balance sheets.

Equity Investments

Our investment in the recently formed CloughHelix JV (Note 8) totaled $6.3 million for the six months ended June 30, 2010. Our investment in the CloughHelix JV is in the form of a loan, which is a fixed non-interest bearing with no stated maturity. We did not make any equity investments during the six-months period ended June 30, 2009. We received the following distributions from our equity investments during the six months ended June 30, 2010 and 2009:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009

	(in thousands)	
Deepwater Gateway.	$ 3,875	$ 3,500
Independence	10,700	13,200
Total	$ 14,575	$ 16,700

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.

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Outlook

We anticipate incurring additional capital expenditures of between $85 million and $95 million over the remainder of 2010. We anticipate that the total amount of our incurred capital expenditures for 2010 will approximate $190 million. The estimates for these capital expenditures may increase or decrease based on various economic factors. We believe internally generated cash flow, cash from future sales of our non-core business assets, and borrowings under our existing credit facilities will provide the capital necessary to fund our 2010 initiatives.

The following table summarizes our contractual cash obligations as of June 30, 2010 and the scheduled years in which the obligations are contractually due:

	Total (1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
			(in thousands)		
Convertible Senior Notes(2)	$ 300,000	$	$	$	$ 300,000
Senior Unsecured Notes	550,000				550,000
Term Loan	412,603	4,326	8,652	399,625	
MARAD debt	117,050	4,533	9,757	10,755	92,005
Revolving Credit Facility					
Loan notes	2,537	2,537			
Interest related to long-term debt	532,886	82,966	160,528	135,246	154,146
Drilling and development costs	25,102	25,102			
Property and equipment	14,378	14,378			
Operating leases(3)	87,767	47,971	37,004	2,527	265
Total cash obligations	$2,042,323	$181,813	$215,941	$548,153	$1,096,416

(1) Excludes unsecured letters of credit outstanding at June 30, 2010 totaling $57.6 million. These letters of credit primarily guarantee various contract bidding, contractual obligations and insurance activities.

(2) Contractual maturity in 2025 (Notes can be redeemed by us or we may be required to purchase them beginning in December 2012). Notes can be converted prior to stated maturity if closing sale price of Helix's common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current

liability in the accompanying balance sheet. At June 30, 2010, the conversion trigger was not met.

(3) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at June 30, 2010 were approximately $76.0 million.

Contingencies

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

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In 2008, we were subcontracted by the prime contractor to perform development work for a large gas field offshore India. Work commenced in the fourth quarter of 2008 and we completed our scope of work in the third quarter of 2009. To date we have collected approximately $303 million related to this project with an amount of trade receivable and claims yet to be collected. We have requested arbitration in India pursuant to the terms of the subcontract to pursue our claims and the prime contractor has also requested arbitration in which it asserts certain counterclaims against us. If we are not successful in resolving these matters through ongoing discussions with the prime contractor then arbitration in India remains a potential remedy. At the time of this filing we believe we will collect our trade receivable balance and we are continuing our efforts to actively pursue our other claim amounts but do not yet have the approvals necessary to recognize additional revenue.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements. We prepare these financial statements in conformity with accounting principles generally accepted in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained, and as our operating environment changes. Please read the following discussion in conjunction with our "Critical Accounting Policies and Estimates" as disclosed in our 2009 Form 10-K.

RECENT ACCOUNTING STANDARDS

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

Item 3. Quantitative and Qualitative Disclosure about Market Risk

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

Commodity Price Risk. As of June 30, 2010, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling approximately 1,710 MMBbl of oil and 16.4 Bcf of natural gas:

Production Period	Instrument Type	Average Monthly Volumes		Weighted Average Price
Crude Oil:				(per barrel)
July 2010 — December 2010	Collar	100	MBbl	$62.50-$80.73

July 2010 — December 2010	Swap	105	MBbl	$76.55
October 2010 — December 2010	Swap	160	MBbl	$81.44
Natural Gas:				(per Mcf)
July 2010 — December 2010	Swap	970.0	Mmcf	$5.81
July 2010 — December 2010	Collar	1,012.0	Mmcf	$6.00 — $6.70
January 2011 — December 2011	Swap	375.0	Mmcf	$5.44

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In the second quarter some of our oil commodity derivative contracts for 480 MBbl covering portions of our anticipated production during the third quarter of 2010 ceased to qualify for hedge accounting as a result of our decision to contract the HP I to BP to assist in the oil spill containment response rather than commencing production from our Phoenix field. The HP I will return to the Phoenix field following its release from its oil spill containment response contract and first production from the Phoenix field is now anticipated late in the third quarter of 2010, All of our remaining commodity derivative contracts designated as cash flow hedges and all remain effective and qualify for hedge accounting as of June 30, 2010 (Note 18). In July 2010, we entered into contracts for 450 MBbls of oil at a contract price of $82.00 per barrel representing a portion of our anticipated production for 2011.

Item 4. Controls and Procedures

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act) as of the end of the fiscal quarter ended June 30, 2010. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended June 30, 2010 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the fiscal quarter ended June 30, 2010.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

The Deepwater Horizon drilling rig explosion in the Gulf of Mexico, the subsequent oil spill and the resulting moratorium on deepwater drilling offshore the United States may impact our oil and gas business located offshore in the Gulf of Mexico and reduce the need for our services in the Gulf of Mexico.

In April 2010, the Deepwater Horizon drilling rig experienced an explosion and fire, and later sank into the Gulf of Mexico. The complete destruction of the Deepwater Horizon rig also resulted in a significant release of crude oil into the Gulf. As a result of this explosion, the resulting oil spill and the inability to stop the oil spill, a moratorium has been placed on offshore deepwater drilling in the United States, which is currently scheduled to be in place effective through November 2010. Our contracting services business, a significant portion of which is in the Gulf of Mexico, provides development services to newly-drilled wells, and therefore relies heavily on the industry’s drilling of new oil and gas wells. In addition, growth in our oil and gas business and any potential disposition of that business will be affected by the ability to develop our portfolio of prospects. We cannot assure you that the moratorium will not be extended or expanded. If the moratorium is not lifted, and with respect to our services business, if our vessels are not redeployed to other locations where we can provide our services at a profitable rate, our business, financial condition and results of operations could be materially affected.

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The Deepwater Horizon rig explosion in the Gulf of Mexico may lead to other restrictions or regulations on offshore drilling in the U.S. Gulf of Mexico and in other areas around the world, which may impact our oil and gas business and reduce the need for our services in those areas.

We do not yet know the extent to which the Deepwater Horizon rig explosion in the Gulf of Mexico may cause the United States or other countries to restrict or further regulate offshore drilling. This event and its aftermath has resulted in proposed legislation and regulation in the United States that could result in additional governmental regulation of the offshore oil and gas exploration and production industry, which may result in substantial increases in costs or delays in drilling or other operations in the Gulf of Mexico, oil and gas projects becoming potentially non-economic, and a corresponding reduced demand for our services. We cannot predict with any certainty the substance or effect of any new or additional regulations. These may include new or additional bonding and safety requirements, and other requirements regarding service vessels and equipment. In addition, any safety requirements or governmental regulations could increase our costs of operation of our oil and gas business and impact our ability to divest the assets of that business. Likewise this could also result in increased costs of operating our contracting services business, and our potential consumers' oil and gas projects becoming non-economic, which could also negatively affect the demand for our contracting services business. If the United States or other countries where we operate enact stricter restrictions on offshore drilling or further regulate offshore drilling or contracting services operations, our business, financial condition and results of operations could be materially affected.

The Deepwater Horizon rig explosion in the Gulf of Mexico and resulting oil spill may make it difficult to buy adequate insurance.

The explosion in the Gulf of Mexico may lead to further tightening of an increasingly difficult market for offshore property damage and well control insurance coverage. Insurers may not continue to offer the type and level of coverage which we currently maintain, and our costs may increase substantially as a result of increased premiums, potentially to the point where coverage is not available on economically manageable terms. In addition, should liability limits be increased via legislative or regulatory action, it is possible that we may not be able to insure certain activities to a desirable level. If liability limits are increased and/or the insurance market becomes more restricted, this may increase the risk as well as the costs of conducting offshore exploration and development activities or result in significant delays, which could materially impact our business, financial condition and results of operations.

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 value of shares that may yet be purchased under the program
April 1 to April 30, 2010(1)	61	$ 16.15		927,887
May 1 to May 31, 2010(1)	114	12.99		927,887
June 1 to June 30, 2010(1)	708,827	11.50	704,400	223,487
	709,002	$ 11.50	704,400	223,487

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

(2) Shares repurchased under previously announced stock buyback program (Note 19). The remaining shares currently available under the share plan were purchased in early July 2010. There are currently no shares available for repurchase under our share plan.

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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.
15.1	Independent Registered Public Accounting Firm's Acknowledgement Letter(1)
23.1	Consent of Huddleston & Co., Inc. (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)
99.2	Report of Huddleston & Co., Inc. (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: July 29, 2010	By: /s/ Owen Kratz Owen Kratz President and Chief Executive Officer (Principal Executive Officer)
Date: July 29, 2010	By: /s/ Anthony Tripodo Anthony Tripodo Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

3.1	2005 Amended and Restated Articles of Incorporation, as amended, of registrant, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by registrant with the Securities and Exchange Commission on March 1, 2006.
3.2	Second Amended and Restated By-Laws of Helix, as amended, incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed by the registrant with the Securities and Exchange Commission on September 28, 2006.
15.1	Independent Registered Public Accounting Firm's Acknowledgement Letter(1)
23.1	Consent of Huddleston & Co., Inc. (1)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer(1)
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