HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
October 31, 2008

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-Q

þ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended September 30, 2008

or

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from __________ to __________

Commission File Number 001-32936
HELIX ENERGY SOLUTIONS GROUP, INC.
(Exact name of registrant as specified in its charter)

Minnesota	**95-3409686**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
400 North Sam Houston Parkway East Suite 400 Houston, Texas	**77060**
(Address of principal executive offices)	*(Zip Code)*

(281) 618-0400
(Registrant s telephone number, including area code)
NOT APPLICABLE
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o
		(Do not check if a smaller reporting company)	

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

As of October 29, 2008, 91,849,691 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

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

	September 30, 2008 (Unaudited)	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 35,761	$ 89,555
Accounts receivable		
Trade, net of allowance for uncollectible accounts of $4,704 and $2,874, respectively	429,853	447,502
Unbilled revenue	51,881	10,715
Costs in excess of billing	95,142	53,915
Other current assets	148,378	125,582
Total current assets	761,015	727,269
Property and equipment	4,663,853	4,088,561
Less accumulated depreciation	(1,056,183)	(843,873)
	3,607,670	3,244,688
Other assets:		
Equity investments	206,805	213,429
Goodwill	1,077,411	1,089,758
Other assets, net	166,593	177,209
	$ 5,819,494	$ 5,452,353
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 344,088	$ 382,767
Accrued liabilities	213,555	221,366
Current maturities of long-term debt	93,540	74,846
Total current liabilities	651,183	678,979
Long-term debt	1,815,083	1,725,541
Deferred income taxes	669,620	625,508
Decommissioning liabilities	185,306	193,650
Other long-term liabilities	74,532	63,183
Total liabilities	3,395,724	3,286,861

Minority interest	296,248	263,926
Convertible preferred stock	55,000	55,000
Commitments and contingencies		
Shareholders equity:		
Common stock, no par, 240,000 shares authorized, 91,841 and 91,385 shares issued, respectively	772,306	755,758
Retained earnings	1,295,370	1,069,546
Accumulated other comprehensive income	4,846	21,262
Total shareholders equity	2,072,522	1,846,566
	$ 5,819,494	$ 5,452,353

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

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

	Three Months Ended September 30,	
	2008	**2007**
Net revenues:		
Contracting services	$ 481,597	$ 318,752
Oil and gas	134,619	141,821
	616,216	460,573
Cost of sales:		
Contracting services	325,186	196,027
Oil and gas	90,205	98,228
	415,391	294,255
Gross profit	200,825	166,318
Gain (loss) on sale of assets, net	(23)	20,701
Selling and administrative expenses	50,700	42,146
Income from operations	150,102	144,873
Equity in earnings of investments	8,886	7,889
Net interest expense and other	23,464	13,467
Income before income taxes	135,524	139,295
Provision for income taxes	54,816	45,327
Minority interest	19,240	10,195
Net income	61,468	83,773
Preferred stock dividends	881	945
Net income applicable to common shareholders	$ 60,587	$ 82,828
Earnings per common share:		
Basic	$ 0.67	$ 0.92
Diluted	$ 0.65	$ 0.88
Weighted average common shares outstanding:		
Basic	90,725	90,111

Diluted	94,779	95,649

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

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

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Net revenues:		
Contracting services	$ 1,107,616	$ 852,332
Oil and gas	499,831	414,870
	1,607,447	1,267,202
Cost of sales:		
Contracting services	797,641	556,546
Oil and gas	295,688	266,958
	1,093,329	823,504
Gross profit	514,118	443,698
Gain on sale of assets, net	79,893	26,385
Selling and administrative expenses	142,405	106,134
Income from operations	451,606	363,949
Equity in earnings of investments	25,964	9,245
Net interest expense and other	68,178	40,765
Income before income taxes	409,392	332,429
Provision for income taxes	154,373	111,711
Minority interest	26,553	21,533
Net income	228,466	199,185
Preferred stock dividends	2,642	2,835
Net income applicable to common shareholders	$ 225,824	$ 196,350
Earnings per common share:		
Basic	$ 2.49	$ 2.18
Diluted	$ 2.40	$ 2.07
Weighted average common shares outstanding:		
Basic	90,598	90,051

Diluted	95,266	96,087

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

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

	Nine Months Ended September 30,	
	2008	**2007**
Cash flows from operating activities:		
Net income	$ 228,466	$ 199,185
Adjustments to reconcile net income to net cash provided by (used in) operating activities		
Depreciation, depletion and amortization	248,578	229,870
Asset impairment charges	23,902	904
Dry hole expense	254	166
Equity in losses of investments, inclusive of impairment charge	2,300	10,841
Amortization of deferred financing costs	3,837	2,315
Stock compensation expense	17,933	11,014
Deferred income taxes	56,575	48,159
Hedge Ineffectiveness	4,045	
Excess tax benefit from stock-based compensation	(1,142)	(28)
Gain on sale of assets	(79,893)	(26,386)
Minority interest	26,553	21,533
Changes in operating assets and liabilities:		
Accounts receivable, net	(48,485)	(36,029)
Other current assets	(5,079)	(38,074)
Income tax payable	739	(115,556)
Accounts payable and accrued liabilities	(79,181)	17,741
Other noncurrent, net	(60,316)	(45,127)
Net cash provided by operating activities	339,086	280,528
Cash flows from investing activities:		
Capital expenditures	(728,803)	(684,653)
Acquisition of businesses, net of cash acquired		(10,202)
Sale of short-term investments		285,395
Investments in equity investments	(708)	(16,132)
Distributions from equity investments, net	4,636	6,363
Proceeds from sales of property	230,261	4,343
Other	(553)	(834)
Net cash used in investing activities	(495,167)	(415,720)
Cash flows from financing activities:		
Repayment of Helix Term Notes	(3,245)	(6,300)
Borrowings on Helix Revolver	847,000	236,300
Repayments on Helix Revolver	(690,000)	(150,300)
Repayment of MARAD borrowings	(4,014)	(3,823)

Borrowings on CDI Revolver	61,100	19,000
Repayments on CDI Revolver	(61,100)	(103,000)
Repayments on CDI Term Notes	(40,000)	
Deferred financing costs	(1,711)	(231)
Capital lease payments	(1,505)	(1,882)
Preferred stock dividends paid	(2,642)	(2,835)
Repurchase of common stock	(3,912)	(9,821)
Excess tax benefit from stock-based compensation	1,142	28
Exercise of stock options, net	2,139	957
Net cash provided by (used in) financing activities	103,252	(21,907)
Effect of exchange rate changes on cash and cash equivalents	(965)	1,271
Net decrease in cash and cash equivalents	(53,794)	(155,828)
Cash and cash equivalents:		
Balance, beginning of year	89,555	206,264
Balance, end of period	$ 35,761	$ 50,436

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

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

Note 1 Basis of Presentation

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. and its majority-owned subsidiaries (collectively, Helix or the Company). Unless the context indicates otherwise, the terms we, us and our in this report refer collectively to Helix and its majority-owned subsidiaries. All material intercompany accounts and transactions have been eliminated. These condensed consolidated financial statements are unaudited, have been prepared pursuant to instructions for the Quarterly Report on Form 10-Q required to be filed with the Securities and Exchange Commission (SEC), and do not include all information and footnotes normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles.

The accompanying condensed consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles and are consistent in all material respects with those applied in our Annual Report on Form 10-K for the year ended December 31, 2007 (2007 Form 10-K). The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and the related disclosures. Actual results may differ from our estimates. Management has reflected all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes are necessary for a fair presentation of the condensed consolidated balance sheets, results of operations, and cash flows, as applicable. Operating results for the period ended September 30, 2008 are not necessarily indicative of the results that may be expected for the year ending December 31, 2008. Our balance sheet as of December 31, 2007 included herein has been derived from the audited balance sheet as of December 31, 2007 included in our 2007 Form 10-K. These condensed consolidated financial statements should be read in conjunction with the annual consolidated financial statements and notes thereto included in our 2007 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 to our own oil and gas properties. Our Contracting Services segment utilizes our vessels, offshore equipment and proprietary technologies to deliver services that reduce finding and development costs and cover the complete lifecycle of an offshore oil and gas field. Our Oil and Gas segment engages in prospect generation, exploration, development and production activities. We operate primarily in the Gulf of Mexico, North Sea, Asia/Pacific and Middle East regions.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. By marginal we mean reservoirs that are no longer wanted by major operators or are too small to be material to them. Our life of field services are organized into five disciplines: construction, well operations, production facilities, reservoir and well technology services, and drilling. We have disaggregated our contracting services operations into three reportable segments in accordance with Financial Accounting Standards Board (FASB) Statement No. 131, *Disclosures about Segments of an Enterprise and Related Information* (SFAS No. 131): Contracting Services (which currently includes subsea construction, well operations and reservoir and well technology services and in the future, drilling); Shelf Contracting; and Production Facilities. Within our contracting services operations, we operate primarily in the Gulf of Mexico, North Sea, Asia/Pacific and Middle East regions, with services that cover the lifecycle of an offshore oil or gas field. The assets of our Shelf Contracting segment are the assets of Cal Dive International, Inc. and its subsidiaries (Cal Dive or CDI). Our ownership in CDI was approximately 58.1% as of September 30, 2008.

Oil and Gas Operations

In 1992 we began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization of our contracting services assets and to achieve incremental returns to our contracting services. Over the last 16 years we have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. This has led to the assembly of services that allows us to create value at key points in the life of a reservoir from exploration through development, life of field management and operating through abandonment.

Note 3 Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. As of September 30, 2008 and December 31, 2007, we had $35.4 million and $34.8 million, respectively, of restricted cash. All of our restricted cash was related to funds required to be escrowed to cover decommissioning liabilities associated with the South Marsh Island 130 (SMI 130) acquisition in 2002 by our Oil and Gas segment. These amounts were reported in Other Assets, Net. We had fully satisfied the escrow requirement as of September 30, 2008. We may use the restricted cash for decommissioning the related field.

The following table provides supplemental cash flow information for the nine months ended September 30, 2008 and 2007 (in thousands):

	Nine Months Ended September 30,	
	2008	**2007**
Interest paid	$77,268	$ 71,906
Income taxes paid	$97,059	$179,107

Non-cash investing activities for the nine months ended September 30, 2008 included $28.6 million of accruals for capital expenditures. Non-cash investing activities for the nine months ended September 30, 2007 were immaterial. The accruals have been reflected in the condensed consolidated balance sheet as an increase in property and equipment and accounts payable.

Note 4 Acquisition of Horizon Offshore, Inc.

On December 11, 2007, CDI acquired 100% of Horizon Offshore, Inc. (Horizon), a marine construction services company headquartered in Houston, Texas. Upon consummating the merger of Horizon into a subsidiary of CDI, each share of Horizon common stock, par value $0.00001 per share, was converted into the right to receive $9.25 in cash and 0.625 shares of CDI s common stock. All shares of Horizon restricted stock that had been issued but had not vested prior to the effective time of the merger became fully vested at such time and converted into the right to receive the merger consideration. CDI issued approximately 20.3 million shares of common stock and paid approximately $300 million in cash to the former Horizon stockholders upon completion of the acquisition. The cash portion of the merger consideration was paid from cash on hand and from borrowings of $375 million under CDI s $675 million credit facility, which consists of a $375 million senior secured term loan and a $300 million senior secured revolving credit facility (see " Note 8 Long-Term Debt below).

We recognized a non-cash pre-tax gain of $151.7 million ($98.6 million net of taxes of $53.1 million) in December 2007 as the value of our interest in CDI s underlying equity increased as a result of CDI s issuance of 20.3 million shares of common stock to former Horizon stockholders. The gain was calculated as the difference in the value of our investment in CDI immediately before and after CDI s stock issuance.

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The aggregate purchase price, including transaction costs of $7.7 million, was approximately $630 million, consisting of $308 million of cash and $322 million of CDI stock. CDI also assumed and repaid approximately $104 million in Horizon s debt, including accrued interest and prepayment penalties, and acquired $171 million of cash. Through the acquisition, CDI acquired nine construction vessels, including four pipelay/pipebury barges, one dedicated pipebury barge, one dive support vessel, one combination derrick/pipelay barge and two derrick barges. The acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values.

The following table summarizes the current adjusted preliminary fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Cash	$ 170,607
Other current assets	165,623
Property and equipment	336,147
Goodwill	257,343
Intangible assets(1)	9,510
Other long-term assets	15,270
Total assets acquired	$ 954,500
Current liabilities	$ 180,846
Long-term debt	87,641
Deferred income taxes	55,789
Other non-current liabilities	100
Total liabilities assumed	$ 324,376
Net assets acquired	$ 630,124

(1) The intangible assets relate to the fair value of contract backlog, customer relationships and non-compete agreements between CDI and certain members of Horizon s senior management as follows (amounts in thousands):

	Fair Value	Amortization Period
Customer relationships	$ 3,060	5 years
Contract backlog	2,960	1.5 years
Non-compete	3,000	1 year
Trade name	490	7 years
Total	$ 9,510	

At September 30, 2008, the net carrying amount for these intangible assets was $5.7 million.

The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and CDI management s review of the final valuations. The primary area of the purchase price allocation that is not yet finalized relates to post-closing purchase price adjustments and the receipt of final valuations. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The results of Horizon are included in our Shelf Contracting segment in the accompanying condensed consolidated statements of operations since the date of purchase.

The following unaudited pro forma combined operating results of us and Horizon for the three and nine months ended September 30, 2007 are presented as if the acquisition had occurred on January 1, 2007 (in thousands, except per share data):

	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2007
Net revenues	$594,694	$1,596,781
Income before income taxes	163,304	390,028
Net income	88,384	192,428
Net income applicable to common shareholders	87,439	189,593
Earnings per common share:		
Basic	$ 0.96	$ 2.09
Diluted	$ 0.93	$ 2.02

The pro forma operating results reflect adjustments for the increases in depreciation related to the step-up of the acquired assets to their fair value and to reflect depreciation calculations under the straight-line method instead of the units-of-production method used by Horizon. Pro forma results include the amortization of identifiable intangible assets. We estimated interest expense based upon increases in CDI s long-term debt to fund the cash portion of the purchase price at an estimated annual interest rate of 7.55% for the three and nine months ended September 30, 2007, based upon the interest rate of CDI s new term loan of three month LIBOR plus 2.25%. The pro forma adjustment to income tax reflects the statutory federal and state income tax impacts of the pro forma adjustments to our pretax income with an applied tax rate of 35%. The unaudited pro forma combined results of operations are not indicative of the actual results had the acquisition occurred on January 1, 2007 or of future operations of the combined companies. All material intercompany transactions between us and Horizon were eliminated.

Note 5 Oil and Gas Properties

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

As of September 30, 2008, we capitalized approximately $19.2 million of exploratory drilling 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 provides a detail of our capitalized exploratory project costs at September 30, 2008 and December 31, 2007 (in thousands):

	September 30, 2008	December 31, 2007
Huey	$ 11,555	$ 11,556
Castleton (part of Gunnison)	7,071	7,071
Other	531	469
Total	$ 19,157	$ 19,096

As of September 30, 2008, the exploratory well costs for Castleton and Huey had been capitalized for longer than one year.

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The following table reflects net changes in suspended exploratory well costs during the nine months ended September 30, 2008 (in thousands):

	2008
Beginning balance at January 1,	$ 19,096
Additions pending the determination of proved reserves	1,088
Reclassifications to proved properties	(773)
Charge to dry hole expense	(254)
Ending balance at September 30,	$ 19,157

Further, the following table details the components of exploration expense for the three and nine months ended September 30, 2008 and 2007 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Delay rental and geological and geophysical costs	$ 1,375	$ 1,426	$ 4,753	$ 5,478
Dry hole expense	270	50	254	166
Total exploration expense	$ 1,645	$ 1,476	$ 5,007	$ 5,644

In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron blocks 371 and 381), in two separate transactions to affiliates of a private independent oil and gas company for total cash consideration of approximately $181.2 million (which included the purchasers share of incurred capital expenditures on these fields), and additional potential cash payments of up to $20 million based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. Decommissioning liabilities will be shared on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million in the first half of 2008.

In May 2008, we sold all our interests in our onshore proved and unproved oil and gas properties located in the states of Texas, Mississippi, Louisiana, Oklahoma, New Mexico and Wyoming (Onshore Properties) to an unrelated investor. We sold these Onshore Properties for cash proceeds of $47.2 million and recorded a related loss of $11.9 million in the second quarter of 2008. Proceeds from the sale of these properties were used to pay down our outstanding loans in May 2008. Included in the cost basis of the Onshore Properties was an $8.1 million allocation of goodwill from our Oil and Gas segment. Following the allocation of goodwill, we performed an impairment test for the remaining goodwill of $704.3 million related to our Oil and Gas segment and no impairment was indicated.

As a result of our unsuccessful development well in January 2008 on Devil s Island (Garden Banks 344), we recognized impairment expense of $14.6 million in the nine months of 2008. Costs incurred as of December 31, 2007 of $20.9 million related to this well were charged to earnings in 2007.

In September 2008, we sustained damage to certain of our contracting services and oil and gas production facilities from Hurricane *Ike*. While we sustained some damage to our own production facilities from Hurricane *Ike*, the larger issue in terms of production recovery involves damage to third party pipelines and onshore processing facilities. The timing of when these facilities will be operational is uncertain and not subject to our control. As of September 30, 2008, we had identified certain shelf production platforms plus other production assets that have sustained extensive damage. Our assessment of damage to our oil and gas production assets is ongoing and thus has not been fully evaluated. We carry comprehensive insurance on all of our operated and non-operated producing and

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non-producing properties, which is subject to approximately $6 million of aggregate deductibles. As of September 2008, we have reached our aggregate deductibles. We believe our comprehensive coverage is sufficient to cover all our repair and inspection costs and capital redrill or rebuild costs as a result of damages sustained by the hurricane. These costs will be recorded as incurred. Insurance reimbursements will be recorded when the realization of the claim for recovery of a loss is deemed probable.

Note 6 Details of Certain Accounts (in thousands)

Other Current Assets consisted of the following as of September 30, 2008 and December 31, 2007:

	September 30, 2008	December 31, 2007
Prepaid insurance	$ 25,395	$ 21,133
Current deferred tax assets	9,945	13,810
Insurance claims to be reimbursed	7,829	10,173
Gas imbalance	6,241	6,654
Inventory	36,686	29,925
Income tax receivable	9,805	8,838
Other prepaids	29,050	14,922
Other receivables	17,433	6,733
Other	5,994	13,394
	$ 148,378	$ 125,582

Other Assets, Net, consisted of the following as of September 30, 2008 and December 31, 2007:

	September 30, 2008	December 31, 2007
Restricted cash	$ 35,351	$ 34,788
Deposits	2,981	8,417
Deferred drydock expenses, net	64,989	47,964
Deferred financing costs	37,640	39,290
Intangible assets with definite lives, net	15,612	22,216
Intangible asset with indefinite life	6,295	7,022
Contract receivables		14,635
Other	3,725	2,877
	$ 166,593	$ 177,209

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Accrued Liabilities consisted of the following as of September 30, 2008 and December 31, 2007:

	September 30, 2008	December 31, 2007
Accrued payroll and related benefits	$ 48,793	$ 50,389
Royalties payable	10,340	21,974
Current decommissioning liability	28,350	23,829
Unearned revenue	11,523	1,140
Billings in excess of costs	10,703	20,403
Insurance claims to be reimbursed	7,829	14,173
Accrued interest	19,890	7,090
Accrued severance[1]	1,953	14,786
Deposit	21,292	13,600
Hedge liability	5,710	10,308
Other	47,172	43,674
	$ 213,555	$ 221,366

(1) Balance at December 31, 2007 was related to payments made to former Horizon personnel in the first quarter of 2008 as a result of the acquisition by CDI. Balance at September 30, 2008 was related to the separation of two of our former executive officers from the Company (See Note 16 Resignation of Executive Officers).

Note 7 Equity Investments

As of September 30, 2008, we have the following material investments that 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 $110.7 million and $112.8 million as of September 30, 2008 and December 31, 2007, respectively, and was included in our Production Facilities segment. Deepwater Gateway sustained minor damage to its production hub from Hurricane *Ike*; however, major infrastructure damage was sustained to the downstream pipeline facilities, causing temporary production shut-ins. Production had not resumed as of September 30, 2008.

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence Hub, LLC (Independence), an affiliate of Enterprise. Independence owns the Independence Hub platform located in Mississippi Canyon block 920 in a water depth of 8,000 feet. First production began in July 2007. Our investment in Independence was $92.9 million and $95.7 million as of September 30, 2008 and December 31, 2007, respectively (including capitalized interest of $6.0 million and $6.2 million at September 30, 2008 and December 31, 2007, respectively), and was included in our Production Facilities segment. Independence did not sustain major damage from Hurricane *Ike* and operations resumed shortly following the hurricane.

Note 8 Long-Term Debt

Senior Unsecured Notes

On December 21, 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 all of our existing restricted domestic subsidiaries, except for CDI and its subsidiaries and Cal Dive I-Title XI, Inc. In addition, any future restricted domestic subsidiaries that guarantee any of our and/or our restricted subsidiaries indebtedness are required to guarantee the Senior Unsecured Notes. CDI, the subsidiaries of CDI, Cal Dive I -Title XI, Inc., and our foreign subsidiaries are not guarantors. We used the proceeds from the Senior Unsecured Notes to repay outstanding indebtedness under our senior secured credit facilities (see below).

Senior Credit Facilities

On July 3, 2006, we entered into a credit agreement (the Senior Credit Facilities) under which we borrowed $835 million in a term loan (the Term Loan) and were initially able to borrow up to $300 million (the Revolving Loans) under a revolving credit facility (the Revolving Credit Facility). The proceeds from the Term Loan were used to fund the cash portion of the Remington Oil and Gas Corporation (Remington) acquisition. This facility was subsequently amended on November 27, 2007, and as part of that amendment, an accordion feature was added that allows for increases in the Revolving Credit Facility up to an additional $150 million, subject to availability of borrowing capacity provided by new or existing lenders. On May 29, 2008, we completed a $120 million increase in the Revolving Credit Facility utilizing this accordion feature. Total borrowing capacity under the Revolving Credit Facility now totals $420 million. The full amount of the Revolving Credit Facility may be used for issuances of letters of credit.

The Term Loan matures on July 1, 2013 and is subject to quarterly scheduled principal payments. As a result of a $400 million prepayment made in December 2007, the quarterly scheduled principal payment was reduced from $2.1 million to $1.1 million. The Revolving Loans mature on July 1, 2011. At September 30, 2008, we had $175.0 million in borrowings outstanding under our Revolving Loans and $23.5 million of unsecured letters of credit, and there was $221.5 million available under the Revolving Loans. In October 2008, we drew down an additional $175.0 million under our Revolving Loans.

The Term Loan currently bears interest at the one-, three- or six-month LIBOR at our election plus a 2.00% margin. Our average interest rate on the Term Loan for the nine months ended September 30, 2008 and 2007 was approximately 5.4% and 7.4%, respectively, including the effects of our interest rate swaps (see below). The Revolving Loans bear interest based on one-, three- or six-month LIBOR at our election plus a margin ranging from 1.00% to 2.25%. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio as provided in the Senior Credit Facilities. Our average interest rate on the Revolving Loans for the nine months ended September 30, 2008 was approximately 5.6%.

As the rates for our Term Loan are subject to market influences and will vary over the term of the Senior Credit Facilities, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. See detailed description related to these swaps in Note 10 Derivative Activities below.

Cal Dive International, Inc. Revolving Credit Facility

In December 2007, CDI entered into a secured credit facility with certain financial institutions, consisting of a $375 million term loan, and a $300 million revolving credit facility. This credit facility replaced the credit facility CDI entered into in November 2006 prior to its initial public offering. On December 11, 2007, CDI borrowed $375 million under the term loan to fund the cash portion of the merger consideration in connection with CDI s acquisition of Horizon and to retire Horizon s existing debt. At September 30, 2008, CDI had $335.0 million of term loan outstanding. In addition, CDI had $6.2 million of unsecured letters of credit outstanding with $293.8 million available under its revolving credit facility.

Loans under this facility are non-recourse to Helix. The term loan and the revolving loans bear interest in relation to the LIBOR. During the nine months ended September 30, 2008 and 2007, CDI s average interest rate was 5.7%.

As the rates for CDI s term loan are subject to market influences and will vary over the term of the loan, CDI entered into an interest rate swap to stabilize cash flows relating to a portion of its interest payments for the CDI term loan. See detailed description related to this swap in Note 10 Derivative Activities below.

Convertible Senior Notes

On March 30, 2005, we issued $300 million of our Convertible Senior Notes at 100% of the principal amount to certain qualified institutional buyers. The Convertible Senior Notes are convertible into cash and, if applicable, shares of our common stock based on the specified conversion rate, subject to adjustment.

The Convertible Senior Notes can be converted prior to the stated maturity under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. During the third quarter of 2008, no conversion triggers were met.

For the three months ended September 30, 2008, shares underlying the Convertible Senior Notes were not included in the calculation of diluted earnings per share because our average share price for the third quarter 2008 was below the conversion price of approximately $32.14 per share. Approximately 0.6 million shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the nine months ended September 30, 2008, and approximately 1.2 million and 1.7 million shares were included in the calculation for the three and nine months ended September 30, 2007, respectively, because our average share price for the respective periods was above the conversion price. 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 maximum number of shares of common stock which may be issued upon conversion of the Convertible Senior Notes is 13,303,770.

MARAD Debt

At September 30, 2008 and December 31, 2007, $123.4 million and $127.5 million was outstanding on our long-term financing for construction of the *Q4000.* 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. 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. In September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027).

In accordance with the Senior Unsecured Notes, amended Senior Credit Facilities, Convertible Senior Notes, MARAD Debt agreements and CDI s credit facility, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, annual working capital and debt-to-equity requirements. As of September 30, 2008, we were in compliance with these covenants and restrictions. The Senior Unsecured Notes and Senior Credit Facilities contain provisions that limit our ability to incur certain types of additional indebtedness.

Other

We, along with Kommandor Rømø, a Danish corporation, formed a joint venture company called Kommandor LLC to convert a ferry vessel into a floating production unit to be named the *Helix Producer I* (HPI). Kommandor LLC qualified as a variable interest entity under FASB Interpretation No. 46 (Revised), *Consolidation of Variable Interest Entities* (FIN 46(R)). We determined that we were the primary beneficiary of Kommandor LLC and thus have consolidated the financial results of Kommandor LLC as of September 30, 2008 in our Production Facilities segment. On June 19, 2007, Kommandor LLC entered into a term loan agreement (Nordea Loan Agreement) with Nordea Bank Norge ASA. On August 29, 2008, the Nordea Loan Agreement was amended. Pursuant to the amended Nordea Loan Agreement, the lenders will make available to Kommandor LLC up to $64.0 million pursuant to a secured term loan facility. We have provided $40 million in interim construction financing to the joint venture on terms that would equal an arms length financing transaction, and Kommandor Rømø has provided $5 million on the same terms. Kommandor LLC will use all amounts borrowed under the Nordea Loan Agreement to repay its existing subordinated indebtedness to us and Kommandor Rømø for the long-term financing of the *HPI* and to fund expenses and fees related to the first stage of the conversion of the *HPI*. Kommandor LLC expects this borrowing to occur in the second quarter of 2009 upon the delivery of the *HPI* after its initial conversion, and at such time, in accordance with the provisions of FIN 46(R), the entire obligation will be included in our consolidated balance sheet. The funding of the amount set forth in the draw request is subject to certain customary conditions.

On June 30, 2008, we entered into a Guaranty Facility Agreement with Nordea and its affiliate, Nordea Bank Finland Plc (together, the Guarantee Provider). This facility provides us with $20 million of capacity for issuances of letters of credit that are required from time to time in our business for performance guarantees or warranty requirements. The facility has a maturity date of 364 days, and may be renewed annually for successive 364-day periods at the lenders option. Fees for letters of credit issued under the facility are 1.00% of the face amount of the letter of credit. This facility is unsecured; however, in the event that the facility is not renewed and letters of credits remain outstanding, we may be required to provide cash collateral for 105% of the face amount of the letters of credit.

Deferred financing costs of $37.6 million and $39.3 million are included in Other Assets, Net as of September 30, 2008 and December 31, 2007, respectively, and are being amortized over the life of the respective loan agreements.

Scheduled maturities of long-term debt and capital lease obligations outstanding as of September 30, 2008 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	CDI Term Loan	Senior Unsecured Notes	Convertible Senior Notes	MARAD Debt	Other[(1)]	Total
Less than one year	$ 4,326	$	$ 80,000	$	$	$ 4,214	$ 5,000	$ 93,540
One to two years	4,326		80,000			4,424		88,750
Two to three years	4,326	175,000	80,000			4,645		263,971
Three to four years	4,326		80,000			4,877		89,203
Four to five years	402,870		15,000			5,120		422,990
Over five years				550,000	300,000	100,169		950,169
Long-term debt	420,174	175,000	335,000	550,000	300,000	123,449	5,000	1,908,623
Current maturities	(4,326)		(80,000)			(4,214)	(5,000)	(93,540)
	$ 415,848	$ 175,000	$ 255,000	$ 550,000	$ 300,000	$ 119,235	$	$ 1,815,083

Long-term debt, less current maturities

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

Total letters of credit outstanding at September 30, 2008 was approximately $43.3 million. These letters of credit primarily guarantee various contract bidding, contractual performance and insurance activities and shipyard commitments. The following table details our interest expense and capitalized interest for the three and nine months ended September 30, 2008 and 2007 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Interest expense	$ 30,468	24,010	95,043	70,257
Interest income	(617)	(1,107)	(2,245)	(7,682)
Capitalized interest	(10,046)	(8,935)	(30,619)	(20,734)
Interest expense, net	$ 19,805	13,968	62,179	41,841

Note 9 Income Taxes

The effective tax rate for the nine months ended September 30, 2008 and 2007 was 38% and 34%, respectively. The effective tax rate for the nine months ended September 30, 2008 increased as compared to the same prior year period because of the following factors:

§ additional deferred tax expense was recorded as a result of the increase in the equity earnings of CDI in excess of our tax basis in CDI;

§ the surrender of the tax losses related to our oil and gas subsidiary in the United Kingdom to other profitable subsidiaries in the United Kingdom that are taxed at a lower rate; and

§ the allocation of goodwill to the cost basis for the Onshore Properties sale is not allowable for tax purposes.

We believe our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain; therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions. See detailed description related to a tax assessment in Note 18 Commitments and Contingencies below.

Note 10 Derivative 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 include 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 currency exchange rate exposure, as well as non-derivative forward sale contracts to reduce commodity price risk on sales of hydrocarbons.

We formally document all relations between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. We also assess, both at inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. Changes in the assumptions used could impact whether the fair value change in the derivative is charged to earnings or accumulated other comprehensive income.

Commodity Derivatives

We have entered into various cash flow hedging costless collar and swap contracts to stabilize cash flows relating to a portion of our expected oil and gas production. These instruments qualified for hedge accounting and were designated as cash flow hedges under FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, (SFAS No. 133). During the third quarter 2008 we settled our open natural gas derivative positions. The resulting gain of $3.9 million was recognized immediately in earnings. Due to production shut-ins and the resultant deferrals caused by Hurricanes *Gustav* and *Ike*, as of September 13, 2008 (the date of Hurricane *Ike*), we no longer meet all of the hedging criteria required by SFAS No. 133 for our open oil derivative positions at September 30, 2008. As a result, we discontinued hedge accounting at September 13, 2008 and the change in fair value from that date through September 30, 2008 was recognized in earnings and all future changes in fair value related

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to these instruments will also be recognized in earnings. We also reclassified the amounts in accumulated other comprehensive income related to the oil derivative contracts as of September 13, 2008 to earnings as a result of the production deferral mentioned above. The aggregate fair value of the hedge instruments was a net liability of $1.0 million and $8.1 million as of September 30, 2008 and December 31, 2007, respectively. We recorded unrealized gains of approximately $14.7 million and $5.3 million, net of tax expense of $7.9 million and $2.8 million, respectively, for the change in fair value of the derivatives during the three and nine months ended September 30, 2008, respectively, in accumulated other comprehensive income. For the three and nine months ended September 30, 2007, we recorded unrealized losses of approximately $0.8 million and $4.4 million, net of tax benefit of $0.4 million and $2.4 million, respectively in accumulated other comprehensive income. During the three and nine months ended September 30, 2008, we reclassified approximately $5.3 million and $24.4 million of losses from other comprehensive income to net revenues upon the sale of the related oil and gas production and approximately $1.0 million from other comprehensive income as a result of the discontinuation of hedge accounting. For the three and nine months ended September 30, 2007, we reclassified approximately $3.2 million and $5.5 million of gains from other comprehensive income to net revenues. No hedge ineffectiveness was recorded in 2007.

As of September 30, 2008, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 2,155 MBbl of oil and 18,076,400 MMbtu of natural gas:

Production Period	**Instrument Type**	**Average Monthly Volumes**	**Weighted Average Price**
Crude Oil:			
October 2008 December 2008	Collar	30 MBbl	$ 60.00 $82.35
October 2008 December 2008	Swap	42 MBbl	$106.25
October 2008 December 2009	Forward Sale	129 MBbl	$71.82
Natural Gas:			
January 2009 December 2009	Forward Sale	1,506,367 MMBtu	$8.23

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.

Subsequent to September 30, 2008, we entered into two additional natural gas costless collars and two natural gas swaps. The costless collars cover an average of 1,029,000 MMBtu per month at an average price of $7.00 to $7.90 per MMBtu for the period from January to December 2009. The swaps cover an average of 1,500,000 MMBtu per month at an average price of $7.02 per MMBtu for November and December 2008. We also entered into an oil costless collar for an average of 50.2 MBbl per month for the period from January to June 2009 at a price of $75.00 to $89.55.

Interest Rate Swaps

As interest rates for some of our long-term debt are subject to market influences and will vary over the term of the debt, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments related to our variable interest debt. Changes in the interest rate swap fair value are deferred to the extent the swap is effective and are recorded as a component of accumulated other comprehensive income until the anticipated interest payments occur and are recognized in interest expense. The ineffective portion of the interest rate swap, if any, will be recognized immediately in earnings.

In September 2006, we entered into various interest rate swaps to stabilize cash flows relating to a portion of our interest payments on our Term Loan. These interest rate swaps qualified for hedge accounting. See Note 8 Long-Term Debt above for a detailed description of our Term Loan. On December 21, 2007, we prepaid a portion of our Term Loan which reduced the notional amount of our interest rate swaps and caused our hedges to become ineffective. As a result, the interest rate swaps no longer qualified for hedge accounting treatment under SFAS No. 133. On January 31, 2008, we re-designated these swaps as cash flow hedges with respect to our outstanding LIBOR-based debt; however, at September 30, 2008, based on the hypothetical derivatives method, we assessed the hedges were not highly effective, as such, no longer qualified for hedge accounting. During the nine months ended September 30, 2008, we recognized $2.5 million of unrealized losses as other expense as a result of the change in fair value of our interest rate swaps. An immaterial amount was recorded in income in the three months ended September 30, 2008 for hedge ineffectiveness. No ineffectiveness was recognized during the three and nine months ended September 30, 2007. As of September 30, 2008 and December 31, 2007, the aggregate fair value of the derivative instruments was a net liability of $4.6 million and $4.7 million, respectively. During the three and nine months ended September 30, 2008, we reclassified approximately $0.4 million and $1.3 million of losses, respectively, from other comprehensive income to interest expense. During the three and nine months ended September 30, 2007, we reclassified approximately $0.1 million and $0.3 million of gains, respectively.

In addition, in April 2008, CDI entered into a two-year interest rate swap to stabilize cash flows relating to a portion of its variable interest payments on the CDI term loan. As of September 30, 2008, these interest rate swaps were highly effective and qualified for hedge accounting. The fair value of the hedge instrument was an asset of $0.8 million as of September 30, 2008.

Foreign Currency Forwards

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 a shipyard contract where the contractual payments are denominated in euros and expected cash outflows relating to certain vessel charters denominated in British pounds. The aggregate fair value of the foreign currency forwards as of September 30, 2008 and December 31, 2007 was a net asset (liability) of ($1.4) million and $1.4 million, respectively.

Note 11 Fair Value Measurements

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

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

Level 1. Observable inputs such as quoted prices in active markets;

Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and

Level 3. Unobservable inputs in which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques noted in SFAS No. 157. The valuation techniques are as follows:

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(a) *Market Approach*. Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

(b) *Cost Approach*. Amount that would be required to replace the service capacity of an asset (replacement cost).

(c) *Income Approach*. Techniques to convert expected future cash flows to a single present amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

The following table provides additional information related to assets and liabilities measured at fair value on a recurring basis at September 30, 2008 (in thousands):

	Level 1	Level 2	Level 3	Total	Valuation Technique
Assets:					
Interest rate swap		$ 803		$ 803	(c)
Liabilities:					
Oil and gas swaps and collars		1,046		1,046	(c)
Foreign currency forwards		1,409		1,409	(c)
Interest rate swaps		4,636		4,636	(c)
Total		$ 7,091		$ 7,091	

Note 12 Comprehensive Income

The components of total comprehensive income for the three and nine months ended September 30, 2008 and 2007 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income	$ 61,468	$ 83,773	$ 228,466	$ 199,185
Foreign currency translation gain (loss)	(26,721)	4,775	(23,929)	9,491
Unrealized gain (loss) on hedges, net	14,365	(1,618)	7,513	(3,709)
Total comprehensive income	$ 49,112	$ 86,930	$ 212,050	$ 204,967

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

	September 30, 2008	December 31, 2007
Cumulative foreign currency translation adjustment	$ 4,331	$ 28,260
Unrealized gain (loss) on hedges, net	515	(6,998)
Accumulated other comprehensive income	$ 4,846	$ 21,262

Note 13 Earnings Per Share

Basic earnings per share (EPS) is computed by dividing the net income available to common shareholders by the weighted average shares of outstanding common stock. The calculation of diluted EPS is similar to basic EPS, except that the denominator includes dilutive common stock equivalents and the income included in the numerator excludes the effects of the impact of dilutive common stock equivalents, if any. The computation of basic and diluted EPS for the three and nine months ended September 30, 2008 and 2007 were as follows (in thousands):

		Three Months Ended September 30, 2008		Three Months Ended September 30, 2007	
		Income	Shares	Income	Shares
Earnings applicable per common share	Basic	$ 60,587	90,725	$ 82,828	90,111
Effect of dilutive securities:					
Stock options			227		368
Restricted shares			196		293
Employee stock purchase plan					2
Convertible Senior Notes					1,244
Convertible preferred stock		881	3,631	945	3,631
Earnings applicable per common share	Diluted	$ 61,468	94,779	$ 83,773	95,649

		Nine Months Ended September 30, 2008		Nine Months Ended September 30, 2007	
		Income	Shares	Income	Shares
Earnings applicable per common share	Basic	$ 225,824	90,598	$ 196,350	90,051
Effect of dilutive securities:					
Stock options			292		386
Restricted shares			170		292
Employee stock purchase plan					4
Convertible Senior Notes			575		1,723
Convertible preferred stock		2,642	3,631	2,835	3,631
Earnings applicable per common share	Diluted	$ 228,466	95,266	$ 199,185	96,087

There were no antidilutive stock options in the three and nine months ended September 30, 2008 and 2007 as the option strike price was below the average market price for the applicable periods. Net income for the diluted EPS calculation for the three and nine months ended September 30, 2008 and 2007 was adjusted to add back the preferred stock dividends as if the convertible preferred stock were converted into 3.6 million shares of common stock.

Note 14 Stock-Based Compensation Plans

We have three stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the 1995 Incentive Plan), the 2005 Long-Term Incentive Plan, as amended (the 2005 Incentive Plan), and the 1998 Employee Stock Purchase Plan, as amended (the ESPP). In addition, CDI has two stock-based compensation plans, the 2006 Long-Term Incentive Plan (the CDI Incentive Plan) and the CDI Employee Stock Purchase Plan (the CDI ESPP) available only to the employees of CDI and its subsidiaries.

During the first nine months of 2008, we granted 509,916 shares of restricted stock and 43,977 restricted stock units to certain key executives, selected management employees and non-employee members of the board of directors under the 2005 incentive plan. The grants generally have a vesting period of 20% per year over five years. The weighted average market value per restricted share and restricted stock unit was $41.11 and $41.50, respectively. There were no stock option grants in the nine months ended September 30, 2008 and 2007.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three and nine months ended September 30, 2008, $0.1 million and $1.0 million, respectively, was recognized as compensation expense related to stock options (of which $0.6 million of compensation expense was recognized in the first half of 2008 related to the acceleration of unvested options per the separation agreements between the Company and two of our former executive officers). For the three and nine months ended September 30, 2008, $3.7 million and $15.2 million, respectively, was recognized as compensation expense related to restricted shares and restricted stock units (of which $1.1 million and $3.5 million, respectively, was related to the CDI Incentive Plan and $3.6 million, was related to the accelerated vesting of restricted shares per the separation agreements between the

Company and two of our former executive officers during the first half of 2008). For the three and nine months ended September 30, 2007, $2.8 million and $8.7 million, respectively, was recognized as compensation expense related to restricted shares (of which $0.5 million and $1.6 million, respectively, was related to the CDI Incentive Plan). Future compensation cost associated with unvested restricted stock awards at September 30, 2008 totaled approximately $46.3 million, of which approximately $14.3 million was related to CDI Incentive Plan.

Employee Stock Purchase Plan

Effective May 12, 1998, we adopted a qualified non-compensatory employee stock purchase plan which allows employees to acquire shares of our common stock through payroll deductions over a six-month period. The purchase price is equal to 85% of the fair market value of the common stock on either the first or last day of the subscription period, whichever is lower. Purchases under the plan are limited to the lesser of 10% of an employee s base salary or $25,000 of our stock value. In January and July 2008, we issued 46,152 and 52,781 shares, respectively, of our common stock to our employees under the ESPP. For the three and nine months ended September 30, 2008, we recognized $0.7 million and $1.8 million, respectively, of compensation expense related to the ESPP and the CDI ESPP (of which $0.3 million and $0.9 million, respectively, of expense was related to the CDI ESPP that became effective third quarter 2007). For the three and nine months ended September 30, 2007, we recognized $0.5 million and $1.5 million, respectively, of compensation expense related to the stock purchased under the ESPP and the CDI ESPP (of which $0.3 million of expense was related to the CDI ESPP that became effective third quarter 2007).

Note 15 Business Segment Information (in thousands)

Our operations are conducted through two lines of business: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131: Contracting Services, Shelf Contracting and Production Facilities. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Production Facilities, and Oil and Gas. The Contracting Services segment includes services such as subsea construction, well operations, and reservoir and well technology services. The Shelf Contracting segment represents the assets of Cal Dive, which consists of assets deployed primarily for diving-related activities and shallow water construction. All material intercompany transactions among the segments have been eliminated in our consolidated results of operations.

We evaluate our performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. The majority of our Production Facilities segment is accounted for under the equity method of accounting. Our investment in Kommandor LLC, a Delaware limited liability company, was consolidated in accordance with FIN 46(R) and is included in our Production Facilities segment.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues				
Contracting Services	$ 284,671	$ 192,331	$ 696,811	$ 484,767
Shelf Contracting	278,709	176,928	595,250	461,412
Oil and Gas	134,619	141,821	499,831	414,870
Intercompany elimination	(81,783)	(50,507)	(184,445)	(93,847)
Total	$ 616,216	$ 460,573	$ 1,607,447	$ 1,267,202
Income from operations				
Contracting Services	$ 56,845	$ 43,697	$ 115,749	$ 98,779
Shelf Contracting	72,719	56,993	109,765	141,438
Production Facilities equity investments(1)	(140)	(182)	(434)	(514)
Oil and Gas	34,198	51,443	248,317	139,345
Intercompany elimination	(13,520)	(7,078)	(21,791)	(15,099)
Total	$ 150,102	$ 144,873	$ 451,606	$ 363,949
Equity in losses of OTSL	$	$	$	$ (10,841)
Equity in earnings of equity investments excluding OTSL	$ 8,886	$ 7,889	$ 25,964	$ 20,086

(1) Includes selling and administrative expense of Production Facilities incurred by us. See equity in earnings of equity investments excluding Offshore Technology Solutions Limited (OTSL) for earnings contribution.

	September 30, 2008	December 31, 2007
Identifiable Assets		
Contracting Services	$ 1,438,669	$ 1,177,431
Shelf Contracting	1,258,374	1,274,050
Production Facilities	448,650	366,634
Oil and Gas	2,673,801	2,634,238
Total	$ 5,819,494	$ 5,452,353

Intercompany segment revenues during the three and nine months ended September 30, 2008 and 2007 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Contracting Services	$ 65,424	$ 31,487	$ 150,465	$ 62,984
Shelf Contracting	16,359	19,020	33,980	30,863
Total	$ 81,783	$ 50,507	$ 184,445	$ 93,847

Intercompany segment profits during the three and nine months ended September 30, 2008 and 2007 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Contracting Services	$ 12,097	$ 865	$ 17,989	$ 3,540
Shelf Contracting	1,423	6,213	3,802	11,559
Total	$ 13,520	$ 7,078	$ 21,791	$ 15,099

Note 16 Resignation of Executive Officers

Martin Ferron resigned as our President and Chief Executive Officer effective February 4, 2008. Concurrently, Mr. Ferron resigned from our Board of Directors. Mr. Ferron remained employed by us through February 18, 2008, after which his employment terminated. At the time of Mr. Ferron s resignation, Owen Kratz, who served as Executive Chairman of Helix, resumed the role and assumed the duties of the President and Chief Executive Officer, and was subsequently elected as President and Chief Executive Officer of Helix. In February 2008, we recognized approximately $5.4 million of compensation expense (inclusive of the expenses recorded for the acceleration of unvested stock options and restricted stock) related to the separation agreement between us and Mr. Ferron.

Wade Pursell resigned as our Chief Financial Officer effective June 25, 2008. Mr. Pursell remained employed by us through July 4, 2008, after which his employment terminated. Anthony Tripodo, who served as the chairman of our audit committee on our Board of Directors, was elected by our Board of Directors as the new Chief Financial Officer effective June 25, 2008, at which time he resigned from our Board of Directors. We recognized approximately $2.0 million of compensation expense (inclusive of the expenses recorded for the acceleration of unvested stock options and restricted stock) related to the separation between us and Mr. Pursell.

Note 17 Related Party Transactions

In April 2000, we acquired a 20% working interest in Gunnison*,* a Deepwater Gulf of Mexico prospect of Kerr-McGee. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or OKCD), the investors of which include our President and Chief Executive Officer, Owen Kratz, and certain former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of Helix s 20% working interest. Owen Kratz, through Class A limited partnership interests in OKCD, personally owns approximately 74% of the partnership. In 2000, OKCD also awarded Class B limited partnership interests to key Helix employees. Production began in December 2003. Payments to OKCD from us totaled $8.8 million and $20.0 million in the three and nine months ended September 30, 2008, respectively, and $5.2 million and $16.9 million in the three and nine months ended September 30, 2007, respectively.

Note 18 Commitments and Contingencies

Commitments

We are converting the *Caesar* (acquired in January 2006 for $27.5 million in cash) into a deepwater pipelay vessel. Total conversion costs are estimated to range between $200 million and $220 million, of which approximately $148 million had been incurred, with an additional $8 million committed, at September 30, 2008. The *Caesar* is expected to be completed in the second quarter of 2009.

We are also constructing the *Well Enhancer*, a multi-service dynamically positioned dive support/well intervention vessel that will be capable of working in the North Sea and West of Shetlands to support our expected growth in that region. Total construction cost for the *Well Enhancer* is expected to range between $200 million to $220 million. We expect the *Well Enhancer* to join our fleet in second quarter 2009. At September 30, 2008, we had incurred approximately $140 million, with an additional $46 million committed to this project.

Further, we, along with Kommandor Rømø, a Danish corporation, formed a joint venture company called Kommandor LLC to convert a ferry vessel into a floating production unit to be named the *Helix Producer I*. The total cost of the ferry and the conversion is estimated to range between $150 million and $160 million which will be funded through project financing of $64 million, with the remaining amount funded through equity contributions from the partners. The partners will guarantee the project financing on a several basis. We have provided $40 million in interim construction financing to the joint venture on terms that would equal an arms length financing transaction, and Kommandor Rømø has provided $5 million on the same terms. Both of these loans will be repaid with the proceeds of the permanent financing facility.

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

Upon completion of the initial conversion, scheduled for second quarter 2009, we will charter the *HPI* from Kommandor LLC, and plan to install, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the *HPI* for use on our Phoenix field. The cost of these additional facilities is estimated to range between $175 million to $195 million and the work is expected to be completed by the end of 2009. As of September 30, 2008, approximately $194 million of costs related to the purchase of the *HPI* ($20 million), conversion of the *HPI* and construction of the additional facilities had been incurred, with an additional $20 million committed. Kommandor LLC qualified as a variable interest entity under FIN 46(R). We determined that we were the primary beneficiary of Kommandor LLC and thus have consolidated the financial results of Kommandor LLC as of September 30, 2008 in our Production Facilities segment. Kommandor LLC has been a development stage enterprise since its formation in October 2006.

Our projected capital expenditures on certain projects have increased as compared to the initially budgeted amounts due primarily to scope changes, escalating costs for certain materials and services due to increasing demand, and the weaker U.S. dollar earlier in 2008 with respect to foreign denominated contracts. In addition, as of September 30, 2008, we have also committed approximately $108.7 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.

On December 2, 2005, we received an order from the U.S. Department of the Interior Minerals Management Service (MMS) that the price thresholds for both oil and gas were exceeded for 2004 production and that royalties are due on such production notwithstanding the provisions of the Outer Continental Shelf Deep Water Royalty Relief Act of 2005 (DWRRA), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalties on certain federal leases up to certain specified production volumes. Our only leases affected by this order are the Gunnison leases. On May 2, 2006, the MMS issued an order that superseded and replaced the December 2005 order, and claimed that royalties on gas production are due for 2003 in addition to oil and gas production in 2004. The May 2006 order also seeks interest on all royalties allegedly due. We filed a timely notice of appeal with respect to both MMS orders. Other operators in the deepwater Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee, the operator of Gunnison. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexico leases, including ours. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government filed a notice of appeal of that decision on December 21, 2007. We do not anticipate that the MMS director will issue decisions in our or the other companies administrative appeals until the Kerr-McGee litigation has been resolved in a final decision. We received an additional order from the MMS dated September 30,

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2008 stating that the price thresholds for oil and gas were exceeded for 2005, 2006 and 2007 production, and that royalties and interest are payable. ERT has appealed that order on the same basis that it appealed the prior MMS orders. As a result of our dispute with the MMS, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed from the Gunnison leases), plus interest, for our portion of the *Gunnison* related MMS claim. The total reserved amount for this matter at September 30, 2008 and December 31, 2007 was approximately $67.3 million and $55.1 million, respectively, and was included in Other Long-term Liabilities in the accompanying condensed consolidated balance sheet included herein. At this time, it is not anticipated that any penalties would be assessed if we are unsuccessful in our appeal.

During the fourth quarter of 2006, Horizon received a tax assessment from the Servicio de Administracion Tributaria (SAT), the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT s assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. On April 21, 2008, CDI filed a petition in Mexico tax court disputing the assessment. We believe that CDI s position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI s potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on our and CDI s financial position and results of operations. Horizon s 2002 through 2007 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 through 2004 currently under audit.

We sustained damage to certain of our oil and gas production facilities in Hurricane *Ike*. We carry comprehensive insurance on all of our operated and non-operated producing and non-producing properties which is subject to approximately $6 million of aggregate deductibles. As of September 2008, we have reached our aggregate deductibles. We believe our comprehensive coverage is sufficient to cover all our repair and inspection costs and capital redrill or rebuild costs as a result of damages sustained by the hurricane. These costs will be recorded as incurred. Insurance reimbursements will be recorded when the realization of the claim for recovery of a loss is deemed probable.

Note 19 Convertible Preferred Stock

On January 8, 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible preferred stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) that is convertible into 1,666,668 shares of our common stock at $15 per share. The preferred stock was issued to a private investment firm. Subsequently in June 2004, the preferred stockholder exercised its existing right and purchased $30 million in additional cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share). In accordance with the January 8, 2003 agreement, the $30 million in additional preferred stock is convertible into 1,964,058 shares of our common stock at $15.27 per share. In the event the holder of the convertible preferred stock elects to redeem into our common stock and our common stock price is below the conversion prices, unless we have elected to settle in cash, the holder would receive additional shares above the 1,666,668 common shares (Series A-1 tranche) and 1,964,058 common shares (Series A-2 tranche). The incremental shares would be treated as a dividend and reduce net income applicable to common shareholders. In the event our common stock price on any date is less than a certain minimum price, we must deliver notice that either (i) the conversion price will be reset to such minimum price or (ii) in the event the holder exercises its redemption rights, we will satisfy our redemption obligations either in cash, or in a combination of cash and common stock with the number of shares of common stock, determined based upon the current market price of our common stock, subject to a maximum number of shares that can be delivered. In the event our redemption obligation is triggered and our obligation cannot be fully satisfied with common stock, we will be required to redeem a portion of the preferred stock in cash. As of October 30, 2008, our stock price has not been below the minimum price since the issuance of the preferred stock.

The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment, payable quarterly in cash or common shares at our option. The dividend rate for the years ended December 31, 2007, 2006 and 2005 was

6.4%, 6.9% and 5.9%, respectively. We paid these dividends in 2007, 2006 and 2005 in cash. The holder may redeem the value of its original and additional investment in the preferred shares to be settled in common stock at the then prevailing market price or cash at our discretion. In the event we are unable to deliver registered common shares, we could be required to redeem in cash.

The proceeds received from the sales of this stock, net of transaction costs, have been classified outside of shareholders equity on the balance sheet below total liabilities. Prior to the conversion, common shares issuable will be assessed for inclusion in the weighted average shares outstanding for our diluted earnings per share using the if converted method based on the lower of our share price at the beginning of the applicable period or the applicable conversion price ($15.00 and $15.27).

Note 20 Recently Issued Accounting Principles

In March 2008, the FASB issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133* (SFAS No. 161). SFAS 161 applies to all derivative instruments and related hedged items accounted for under SFAS No. 133. SFAS No. 161 asks entities to provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. The standard is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged, but not required. We are currently evaluating the impact of this statement on our disclosures.

In May 2008, the FASB issued FASB Staff Position (FSP) APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)* (FSP APB 14-1 *)*. The FSP would require the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount would be amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. The effective date of FSP APB 14-1 is for fiscal years beginning after December 15, 2008 and requires retrospective application to all periods reported (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). The FSP does not permit early application. This FSP changes the accounting treatment for our Convertible Senior Notes. FSP APB 14-1 will increase our non-cash interest expense for our past and future reporting periods. In addition, it will reduce our long-term debt and increase our shareholders equity for the past reporting periods. We are currently evaluating the impact of this FSP on our consolidated financial statements.

In June 2008, the FASB issued FSP Emerging Issues Task Force 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1). This FSP would require unvested share-based payment awards containing non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) to be included in the computation of basic EPS according to the two-class method. The effective date of FSP EITF 03-6-1 is for fiscal years beginning after December 15, 2008 and requires all prior-period EPS data presented to be adjusted retrospectively (including interim financial statements, summaries of earnings, and selected financial data) to conform with the provisions of this FSP. FSP EITF 03-6-1 does not permit early application. This FSP changes our calculation of basic and diluted EPS and will lower previously reported basic and diluted EPS as weighted-average shares outstanding used in the EPS calculation will increase. We are currently evaluating the impact of this statement on our consolidated financial statements.

Also in June 2008, the FASB issued Emerging Issues Task Force Issue No. 07-5, *Determining Whether an Instrument (or Imbedded Feature) is Indexed to an Entity s Own Stock* (EIFT 07-5). This issue addresses the determination of whether an instrument (or an embedded feature) is indexed to an entity s own stock. This issue is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application by an entity that has previously adopted an alternative accounting policy is not permitted. We are currently evaluating the impact of this statement on our consolidated financial statements.

Note 21 Condensed Consolidated Guarantor and Non-Guarantor Financial Information

The payment of obligations under the Senior Unsecured Notes is guaranteed by all of our restricted domestic subsidiaries (Subsidiary Guarantors) except for Cal Dive and its subsidiaries and Cal Dive I-Title XI, Inc. Each of these Subsidiary Guarantors is included in our consolidated financial statements and has fully and unconditionally guaranteed the Senior Unsecured Notes on a joint and several basis. As a result of these guarantee arrangements, we are required to present the following condensed consolidating financial information. The accompanying guarantor financial information is presented on the equity method of accounting for all periods presented. Under this method, investments in subsidiaries are recorded at cost and adjusted for our share in the subsidiaries cumulative results of operations, capital contributions and distributions and other changes in equity. Elimination entries related primarily to the elimination of investments in subsidiaries and associated intercompany balances and transactions.

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

	As of September 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 3,216	$ 231	$ 32,314	$	$ 35,761
Accounts receivable, net	124,501	122,783	337,217	(7,625)	576,876
Other current assets	113,689	57,529	49,563	(72,403)	148,378
Total current assets	241,406	180,543	419,094	(80,028)	761,015
Intercompany	93,997	120,873	(175,661)	(39,209)	
Property and equipment, net	157,913	2,224,582	1,228,918	(3,743)	3,607,670
Other assets:					
Equity investments	3,202,791	37,088	206,805	(3,239,879)	206,805
Goodwill		749,670	328,016	(275)	1,077,411
Other assets, net	53,129	38,744	103,525	(28,805)	166,593
	$ 3,749,236	$ 3,351,500	$ 2,110,697	$ (3,391,939)	$ 5,819,494
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities:					
Accounts payable	$ 57,877	$ 171,124	$ 122,146	$ (7,059)	$ 344,088
Accrued liabilities	62,057	64,822	91,037	(4,361)	213,555
Income taxes payable	(109,650)	103,906	1,895	3,849	
Current maturities of long-term debt	4,326		163,567	(74,353)	93,540
Total current liabilities	14,610	339,852	378,645	(81,924)	651,183
Long-term debt	1,440,848		399,720	(25,485)	1,815,083
Deferred income taxes	167,432	320,740	186,825	(5,377)	669,620
Decommissioning liabilities		181,510	3,796		185,306
Other long-term liabilities	995	71,182	5,380	(3,025)	74,532
Due to parent	(37,028)	(8,329)	37,028	8,329	
Total liabilities	1,586,857	904,955	1,011,394	(107,482)	3,395,724
Minority interest				296,248	296,248
Convertible preferred stock	55,000				55,000
Shareholders equity	2,107,379	2,446,545	1,099,303	(3,580,705)	2,072,522
	$ 3,749,236	$ 3,351,500	$ 2,110,697	$ (3,391,939)	$ 5,819,494

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

	As of December 31, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 3,507	$ 2,609	$ 83,439	$	$ 89,555
Accounts receivable, net	99,354	104,339	308,439		512,132
Other current assets	74,665	45,752	55,529	(50,364)	125,582
Total current assets	177,526	152,700	447,407	(50,364)	727,269
Intercompany	38,989	51,001	(83,546)	(6,444)	
Property and equipment, net	92,864	2,093,194	1,060,298	(1,668)	3,244,688
Other assets:					
Equity investments	3,015,250	30,046	213,429	(3,045,296)	213,429
Goodwill		757,752	332,281	(275)	1,089,758
Other assets, net	59,554	40,686	111,259	(34,290)	177,209
	$ 3,384,183	$ 3,125,379	$ 2,081,128	$ (3,138,337)	$ 5,452,353
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities:					
Accounts payable	$ 43,774	$ 207,222	$ 131,730	$ 41	$ 382,767
Accrued liabilities	40,415	71,945	110,443	(1,437)	221,366
Income taxes payable	1,798	159	4,467	(6,424)	
Current maturities of long-term debt	4,327	2	113,975	(43,458)	74,846
Total current liabilities	90,314	279,328	360,615	(51,278)	678,979
Long-term debt	1,287,092		463,934	(25,485)	1,725,541
Deferred income taxes	137,967	318,492	178,275	(9,226)	625,508
Decommissioning liabilities		189,639	4,011		193,650
Other long-term liabilities	3,294	56,325	9,244	(5,680)	63,183
Due to parent	(35,681)	98,504	37,028	(99,851)	
Total liabilities	1,482,986	942,288	1,053,107	(191,520)	3,286,861
Minority interest				263,926	263,926
Convertible preferred stock	55,000				55,000
Shareholders equity	1,846,197	2,183,091	1,028,021	(3,210,743)	1,846,566
	$ 3,384,183	$ 3,125,379	$ 2,081,128	$ (3,138,337)	$ 5,452,353

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

	Three Months Ended September 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 103,612	$ 234,650	$ 366,138	$ (88,184)	$ 616,216
Cost of sales	91,692	148,090	248,890	(73,281)	415,391
Gross profit	11,920	86,560	117,248	(14,903)	200,825
Gain on sale of assets, net			(23)		(23)
Selling and administrative expenses	13,559	11,938	26,570	(1,367)	50,700
Income from operations	(1,639)	74,622	90,655	(13,536)	150,102
Equity in earnings (losses) of investments	83,140	1,885	8,886	(85,025)	8,886
Net interest expense and other	316	7,661	14,606	881	23,464
Income before income taxes	81,185	68,846	84,935	(99,442)	135,524
Provision for income taxes	10,775	25,550	23,945	(5,454)	54,816
Minority interest				19,240	19,240
Net income	70,410	43,296	60,990	(113,228)	61,468
Preferred stock dividends	881				881
Net income applicable to common shareholders	$ 69,529	$ 43,296	$ 60,990	$ (113,228)	$ 60,587

	Three Months Ended September 30, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 55,409	$ 199,847	$ 261,381	$ (56,064)	$ 460,573
Cost of sales	39,489	142,257	161,744	(49,235)	294,255
Gross profit	15,920	57,590	99,637	(6,829)	166,318
Gain on sale of assets, net	1,738	18,805	158		20,701
Selling and administrative expenses	12,019	11,950	18,801	(624)	42,146
Income from operations	5,639	64,445	80,994	(6,205)	144,873
Equity in earnings of investments	81,334	7,456	7,889	(88,790)	7,889
Net interest expense and other	(3,938)	13,391	3,230	784	13,467
Income before income taxes	90,911	58,510	85,653	(95,779)	139,295
Provision for income taxes	7,320	17,469	22,990	(2,452)	45,327
Minority interest				10,195	10,195

Net income	83,591		41,041		62,663		(103,522)		83,773
Preferred stock dividends	945								945
Net income applicable to common shareholders	$ 82,646	$	41,041	$	62,663	$	(103,522)	$	82,828

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

	Nine Months Ended September 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 278,602	$ 684,357	$ 847,379	$ (202,891)	$ 1,607,447
Cost of sales	242,553	419,298	609,185	(177,707)	1,093,329
Gross profit	36,049	265,059	238,194	(25,184)	514,118
Gain on sale of assets, net		79,707	186		79,893
Selling and administrative expenses	30,854	41,015	73,937	(3,401)	142,405
Income from operations	5,195	303,751	164,443	(21,783)	451,606
Equity in earnings of investments	267,256	7,042	25,964	(274,298)	25,964
Net interest expense and other	6,693	32,129	30,309	(953)	68,178
Income before income taxes	265,758	278,664	160,098	(295,128)	409,392
Provision for income taxes	25,244	96,600	41,310	(8,781)	154,373
Minority interest				26,553	26,553
Net income	240,514	182,064	118,788	(312,900)	228,466
Preferred stock dividends	2,642				2,642
Net income applicable to common shareholders	$ 237,872	$ 182,064	$ 118,788	$ (312,900)	$ 225,824

	Nine Months Ended September 30, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 146,293	$ 562,946	$ 667,173	$ (109,210)	$ 1,267,202
Cost of sales	106,468	378,973	431,697	(93,634)	823,504
Gross profit	39,825	183,973	235,476	(15,576)	443,698
Gain on sale of assets, net	1,959	20,980	3,446		26,385
Selling and administrative expenses	23,759	34,483	49,247	(1,355)	106,134
Income from operations	18,025	170,470	189,675	(14,221)	363,949
Equity in earnings of investments	199,701	13,511	9,245	(213,212)	9,245
Net interest expense and other	(7,222)	36,128	11,075	784	40,765
Income before income taxes	224,948	147,853	187,845	(228,217)	332,429
Provision for income taxes	16,014	46,276	54,677	(5,256)	111,711
Minority interest			113	21,420	21,533

Net income	208,934	101,577	133,055	(244,381)	199,185
Preferred stock dividends	2,835				2,835
Net income applicable to common shareholders	$ 206,099	$ 101,577	$ 133,055	$ (244,381)	$ 196,350

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

	Nine Months Ended September 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income	$ 240,514	$ 182,064	$ 118,788	$ (312,900)	$ 228,466
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates			2,300		2,300
Equity in earnings of affiliates	(267,257)	(7,041)		274,298	
Other adjustments	(62,637)	115,320	23,629	32,008	108,320
Net cash (used in) provided by operating activities	(89,380)	290,343	144,717	(6,594)	339,086
Cash flows from investing activities:					
Capital expenditures	(89,451)	(420,044)	(219,308)		(728,803)
Investments in equity investments			(708)		(708)
Distributions from equity investments, net			4,636		4,636
Proceeds from sales of property		228,483	1,778		230,261
Other		(553)			(553)
Net cash used in investing activities	(89,451)	(192,114)	(213,602)		(495,167)
Cash flows from financing activities:					
Borrowings on revolvers	847,000		61,100		908,100
Repayments on revolvers	(690,000)		(61,100)		(751,100)
Repayments of debt	(3,245)		(44,014)		(47,259)
Deferred financing costs	(1,711)				(1,711)
Preferred stock dividends paid	(2,642)				(2,642)
Capital lease payments		(2)	(1,503)		(1,505)
Repurchase of common stock	(3,912)				(3,912)
Excess tax benefit from stock-based compensation	1,142				1,142
Exercise of stock options, net	2,139				2,139
Intercompany financing	29,769	(100,605)	64,242	6,594	

Net cash provided by (used in) financing activities	178,540	(100,607)	18,725	6,594	103,252
Effect of exchange rate changes on cash and cash equivalents			(965)		(965)
Net decrease in cash and cash equivalents	(291)	(2,378)	(51,125)		(53,794)
Cash and cash equivalents:					
Balance, beginning of year	3,507	2,609	83,439		89,555
Balance, end of period	$ 3,216	$ 231	$ 32,314	$	$ 35,761

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

	Nine Months Ended September 30, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income	$ 208,934	$ 101,577	$ 133,055	$ (244,381)	$ 199,185
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates			10,841		10,841
Equity in earnings of affiliates	(199,701)	(13,511)		213,212	
Other adjustments	(187,268)	176,475	37,698	43,597	70,502
Net cash (used in) provided by operating activities	(178,035)	264,541	181,594	12,428	280,528
Cash flows from investing activities:					
Capital expenditures	(48,013)	(504,954)	(131,686)		(684,653)
Acquisition of businesses, net of cash acquired		(136)	(10,066)		(10,202)
Sale of short-term investments	285,395				285,395
Investments in equity investments			(16,132)		(16,132)
Distributions from equity investments, net			6,363		6,363
Proceeds from sales of property		2,003	2,340		4,343
Other		(834)			(834)
Net cash provided by (used in) investing activities	237,382	(503,921)	(149,181)		(415,720)
Cash flows from financing activities:					
Borrowings on revolvers	236,300		19,000		255,300
Repayments on revolvers	(150,300)		(103,000)		(253,300)
Repayments of debt	(6,300)		(3,823)		(10,123)
Deferred financing costs	(216)		(15)		(231)
Capital lease payments			(1,882)		(1,882)
Preferred stock dividends paid	(2,835)				(2,835)
Repurchase of common stock	(9,821)				(9,821)
Excess tax benefit from stock-based compensation	28				28

Exercise of stock options, net	957				957
Intercompany financing	(267,028)	237,481	41,975	(12,428)	
Net cash provided by (used in) financing activities	(199,215)	237,481	(47,745)	(12,428)	(21,907)
Effect of exchange rate changes on cash and cash equivalents			1,271		1,271
Net decrease in cash and cash equivalents	(139,868)	(1,899)	(14,061)		(155,828)
Cash and cash equivalents:					
Balance, beginning of year	142,489	7,690	56,085		206,264
Balance, end of period	$ 2,621	$ 5,791	$ 42,024	$	$ 50,436

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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 or 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 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, p intend, will, continue, may, potential, achieve, should, could and similar terms and phrases are forward statements. Included in forward-looking statements are, among other things:

- statements regarding our anticipated production volumes, results of exploration, exploitation, development, acquisition or operations expenditures, and current or prospective reserve levels, with respect to any property or well;
- statements 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 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 our business strategy, our business plans or any other plans, forecasts or objectives, any or all of which is subject to change; and
- statements regarding anticipated developments, industry trends, performance or industry ranking.

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:

- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- 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;
- the success 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 economic, market, industry or business conditions.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk and uncertainties set forth above as well as those described under the heading Risk Factors in our 2007 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. These risk factors are not intended to be a discussion of all potential risks and uncertainties as it is not possible to predict or identify all risk factors. Although we believe the expectations reflected in the forward-looking statements are based upon reasonable assumptions, we can give no assurance that we will attain these expectations or that any deviation will not be material. All forward-looking statements in this report are based upon information available to us on the date of this report. You should not place undue reliance on these forward-looking statements. 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.

Economic Outlook

The recent volatility in the equity and credit markets has led to increased uncertainty regarding the outlook of the global economy. This heightened uncertainty and the likelihood of a global decrease in hydrocarbon demand has led to declining commodity prices, which negatively impacts our oil and gas operations. These events have contributed to a decline in our stock price and corresponding market capitalization. Further stock price or commodity price decreases in the fourth quarter could result in noncash impairments of long-lived assets and goodwill. At September 30, 2008, we had $1.1 billion of goodwill recorded in conjunction with past business combinations and $6.3 million of intangible assets with indefinite useful lives. Further, our contracting services operations may be negatively impacted by the declining commodity prices as these factors may cause our customers, the oil and gas companies, to curtail capital spending. At the moment, it is still too soon to predict to what extent current events will affect our overall activity levels in 2009. The long-term outlook for our business remains generally favorable as the need for the continual replenishment of oil and gas production should drive the long-term need for our services. In addition, as our subsea construction operations primarily support capital projects with long lead times, they are less likely to be impacted by temporary economic down-turns. Further, we have entered into additional commodity hedges in October 2008 to minimize cash flow risks related to declining commodity prices.

In light of the current credit crisis, in October 2008, we drew down an additional $175 million on our Revolving Credit Facility to ensure adequate and readily available liquidity. After this draw down, we have approximately $44 million of additional capacity remaining under our Revolving Credit Facility. Further, we have reduced our planned capital expenditures for the fourth quarter of 2008 and 2009 to include only completion of major projects and limited new exploration drilling. We believe our actions described above will allow us to have sufficient liquidity.

RESULTS OF OPERATIONS

Our operations are conducted through two lines of business: contracting services operations and oil and gas operations.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing production economics, particularly from marginal fields. Our life of field services are organized into five disciplines: construction, well operations, production facilities, reservoir and well tech services, and drilling. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS No. 131: Contracting Services (which currently includes subsea construction, well operations and reservoir and well technology services and in the future, drilling), Shelf Contracting, and Production Facilities. Within our contracting services operations, we operate primarily in the Gulf of Mexico, North Sea, Asia/Pacific and Middle East regions, with services that cover the lifecycle of an offshore oil or gas field. The Shelf Contracting segment consists of assets deployed primarily for diving-related activities and shallow water construction. The assets of our Shelf Contracting segment are the assets of Cal Dive. Our ownership in Cal Dive was 58.1% as of September 30, 2008. As of September 30, 2008, our contracting services operations had backlog of approximately $1.2 billion, of which over $370.5 million was expected to be completed in the remainder of 2008.

Oil and Gas Operations

In 1992 we began our oil and gas operations to provide a more efficient solution to offshore abandonment, to expand our off-season asset utilization of our contracting services business and to achieve incremental returns to our contracting services. Over the last 16 years, we have evolved this business model to include not only mature oil and gas properties but also proved and unproved reserves yet to be developed and explored. By owning oil and gas reservoirs and prospects, we are able to utilize the services we otherwise provide to third parties to create value at key points in the life of our own reservoirs including during the exploration and development stages, the field management stage and the abandonment stage. It is also a feature of our business model to opportunistically monetize part of the created reservoir value, through sales of working interests, in order to help fund field development and reduce gross profit deferrals from our Contracting Services operations. Therefore the reservoir value we create is realized through oil and gas production and/or monetization of working interest stakes.

Comparison of Three Months Ended September 30, 2008 and 2007

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

	Three Months Ended September 30, 2008	**2007**	**Increase/ (Decrease)**
Revenues (in thousands)			
Contracting Services	$ 284,671	$ 192,331	$ 92,340
Shelf Contracting	278,709	176,928	101,781
Oil and Gas	134,619	141,821	(7,202)
Intercompany elimination	(81,783)	(50,507)	(31,276)
	$ 616,216	$ 460,573	$ 155,643
Gross profit (in thousands)			
Contracting Services	$ 77,388	$ 59,864	$ 17,524
Shelf Contracting	92,543	69,939	22,604
Oil and Gas	44,414	43,593	821
Intercompany elimination	(13,520)	(7,078)	(6,442)
	$ 200,825	$ 166,318	$ 34,507
Gross Margin			
Contracting Services	27%	31%	(4 pts)
Shelf Contracting	33%	40%	(7 pts)
Oil and Gas	33%	31%	2 pts
Total company	33%	36%	(3 pts)
Number of vessels(1)/ Utilization(2)			
Contracting Services:			

Subsea construction vessels	10/98%	9/93%
Well operations	2/100%	2/83%
ROVs	47/76%	37/85%
Shelf Contracting	30/78%	25/74%

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

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

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Intercompany segment revenues during the three months ended September 30, 2008 and 2007 were as follows (in thousands):

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Increase/ (Decrease)
Contracting Services	$ 65,424	$ 31,487	$ 33,937
Shelf Contracting	16,359	19,020	(2,661)
	$ 81,783	$ 50,507	$ 31,276

Intercompany segment profit during the three months ended September 30, 2008 and 2007 was as follows (in thousands):

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Increase/ (Decrease)
Contracting Services	$ 12,097	$ 865	$ 11,232
Shelf Contracting	1,423	6,213	(4,790)
	$ 13,520	$ 7,078	$ 6,442

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

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Increase/ (Decrease)
Oil and Gas information			
Oil production volume (MBbls)	573	853	(280)
Oil sales revenue (in thousands)	$ 61,436	$ 61,137	$ 299
Average oil sales price per Bbl (excluding hedges)	$ 114.64	$ 74.38	$ 40.26
Average realized oil price per Bbl (including hedges)	$ 107.14	$ 71.63	$ 35.51
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 30,316		
Change in production volume (in thousands)	(30,017)		
Total increase in oil sales revenue (in thousands)	$ 299		
Gas production volume (MMcf)	7,013	10,508	(3,495)
Gas sales revenue (in thousands)	$ 71,658	$ 73,958	$ (2,300)
Average gas sales price per mcf (excluding hedges)	$ 10.37	$ 6.51	$ 3.86
Average realized gas price per mcf (including hedges)	$ 10.22	$ 7.04	$ 3.18
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 33,416		
Change in production volume (in thousands)	(35,716)		
Total increase in gas sales revenue (in thousands)	$ (2,300)		

Total production (MMcfe)	10,453	15,630	(5,177)
Price per Mcfe	$ 12.73	$ 8.64	$ 4.09
Oil and Gas revenue information (in thousands)			
Oil and gas sales revenue	$ 133,094	$ 135,095	$ (2,001)
Miscellaneous revenues[(1)]	1,525	6,726	(5,201)
	$ 134,619	$ 141,821	$ (7,202)

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

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

	Three Months Ended September 30, 2008		2007	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 21,945	$ 2.10	$ 22,515	$ 1.44
Workover	5,325	0.51	2,237	0.14
Transportation	1,551	0.15	1,031	0.07
Repairs and maintenance	6,002	0.57	2,941	0.19
Overhead and company labor	1,261	0.12	2,808	0.18
Total	$ 36,084	$ 3.45	$ 31,532	$ 2.02
Depletion expense	$ 35,802	$ 3.42	$ 50,746	$ 3.25
Abandonment	6,534	0.63	12,503	0.80
Accretion expense	3,266	0.31	2,836	0.18
Impairment	6,874	0.66		

(1) Excludes exploration expense of $1.6 million and $1.5 million for the three months ended September 30, 2008 and 2007, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. During the three months ended September 30, 2008, our revenues increased by 34% as compared to the same period in 2007. Contracting Services revenues increased primarily due to the following:

§ addition of two chartered subsea construction vessels as well as an overall increase in utilization of our subsea construction vessels;

§ overall increase in utilization of our well operations vessels and higher dayrates realized; and

§ strong performance by our robotics division driven by higher number of ROVs in our overall fleet and additional services provided as a result of Hurricanes *Gustav* and *Ike*.

Shelf Contracting revenues increased primarily as a result of the revenue contributions from certain former Horizon assets acquired in December 2007. This increase was partially offset by adverse weather downtime due to Hurricanes *Gustav* and *Ike*.

Oil and Gas revenues decreased 5% during the three months ended September 30, 2008 as compared to the same period in 2007. The decrease in oil and gas revenues was due to lower oil and gas production. In September 2008, we sustained damage to certain of our oil and gas production facilities from Hurricane *Ike*. While we sustained some damage to our own production facilities from Hurricane *Ike*, ramp up of production is limited significantly by damage to third party pipelines and onshore processing facilities. The timing of when these facilities will be operational is uncertain and not subject to our control. We anticipate reaching pre-hurricane production levels in January 2009. We expect fourth quarter production to range from 7.5 Bcfe to 8.0 Bcfe with a ramp up of production in first quarter 2009 to surpass second quarter 2008 levels as a result of incremental production anticipated from the Noonan gas discovery. Production declines during third quarter 2008 were also attributable to the loss of production at the Tiger deepwater field (Green Canyon 195) in late 2007, along with a natural decline in shelf production as a result of reduction in capital allocable to shelf exploration. These decreases were partially offset by a 50% increase in realized oil prices, net of hedges in place, and a 45% increase in realized gas prices, net of hedges in place.

Gross Profit. Gross profit in the third quarter of 2008 increased $34.5 million as compared to the same period in 2007. This increase was primarily due to higher gross profit attributable to our Contracting

Services and Shelf Contracting segments. These increases were partially offset by decreases in Oil and Gas segment gross profit as a result of temporary production shut-ins as described above.

Contracting Services gross profit increased 29% for the reasons stated above, However, Contracting Services gross margin decreased by four points. The decline in gross margin was primarily due to lower margins realized on certain international deepwater pipelay projects during the quarter as some services were provided to the customer under various change orders; however, no revenue was recognized associated with this work as certain revenue recognition criteria were not met at September 30, 2008. We expect our Contracting Services gross margin to improve in the remainder of the year as these change orders are approved by our customers.

Shelf Contracting gross profit increase was primarily attributable to gross profit contributions from certain Horizon assets, offset partially by lower vessel utilization, adverse weather conditions described above, and higher depreciation and amortization due primarily to assets purchased in the Horizon acquisition.

As described above, we sustained damage to certain of our contracting services and oil and gas production facilities in Hurricanes *Gustav* and *Ike*. For the three months ended September 30, 2008, we incurred approximately $3.7 million of additional repair and maintenance expense as a result of the hurricanes. In addition, in September 2008, we recorded impairment expense of $6.7 million related to the Tiger deepwater field, as we expect to abandon the property earlier than planned as a result of damage caused by Hurricane *Ike*. We carry comprehensive insurance on all of our operated and non-operated producing and non-producing properties which is subject to approximately $6 million of aggregate deductibles. As of September 30, 2008, we have reached our aggregate deductibles. We believe our comprehensive coverage is sufficient to cover all our repair and inspection costs and capital redrill or rebuild costs as a result of damages sustained by the hurricanes.

Gain on Sale of Assets, Net. Gain on sale of assets, net, decreased by $20.7 million during the three months ended September 30, 2008 as compared to the same prior year period. The decrease was primarily due to a gain of $18.8 million recognized in third quarter 2007 relate to the sale of a 30% interest in our Phoenix oilfield (Green Canyon Blocks 236/237), the Boris Oilfield (Green Canyon Block 282), and the Little Burn Oilfield (Green Canyon Block 238).

Selling and Administrative Expenses. Selling and administrative expenses of $50.7 million for the third quarter of 2008 were $8.6 million higher than the $42.1 million incurred in the same prior year period. The increase was due primarily to higher overhead (primarily related to the Horizon acquisition) to support our growth. Selling and administrative expenses decreased slightly to 8% of revenues in the three months ended September 30, 2008 as compared to 9% in the same prior year period.

Equity in Earnings of Investments. Equity in earnings of investments increased slightly by $1.0 million during the three months ended September 30, 2008 as compared to the same prior year period. Our equity in earnings related to our 20% investment in Independence Hub increased $2.2 million over the same prior year period as first production at Independence Hub began in July 2007. This increase was partially offset by a $1.2 million decrease in equity earnings related to our investment in Deepwater Gateway. Deepwater Gateway sustained minor damage to its production hub from Hurricane *Ike*; however, major infrastructure damage was sustained to the downstream pipeline facilities, causing temporary production shut-ins. Production had not resumed as of September 30, 2008. We expect production to resume to pre-hurricane level by first quarter 2009.

Net Interest Expense and Other. We reported net interest and other expense of $23.5 million in third quarter 2008 as compared to $13.5 million in the same prior year period. Gross interest expense of $30.5 million during the three months ended September 30, 2008 was higher than the $24.0 million incurred in 2007 due to overall higher levels of indebtedness as a result of our Senior Unsecured Notes and CDI s term loan, which both closed in December 2007. In addition, we drew down our revolver by $60 million in third quarter 2008. Offsetting the increase in interest expense was $10.0 million of capitalized interest and $0.6 million of interest income in the third quarter of 2008, compared with $8.9 million of capitalized interest and $1.1 million of interest income in the same prior year period.

Provision for Income Taxes. Income taxes increased to $54.8 million in the three months ended September 30, 2008 compared with $45.3 million in the same prior year period. The increase was primarily due to increased profitability. In addition, the effective tax rate of 40% for the third quarter of 2008 was higher than the 33% for the third quarter of 2007. The effective tax rate for third quarter 2008 increased primarily because of additional deferred tax expense recorded as a result of the increase in the equity earnings of CDI in excess of our tax basis. Further, the surrender of the tax losses related to our oil and gas subsidiary in the United Kingdom to other profitable subsidiaries in the United Kingdom that are taxed at a lower rate also contributed to the increase in our consolidated effective tax rate.

Comparison of Nine Months Ended September 30, 2008 and 2007

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

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Increase/ (Decrease)
Revenues (in thousands) -			
Contracting Services	$ 696,811	$ 484,767	$ 212,044
Shelf Contracting	595,250	461,412	133,838
Oil and Gas	499,831	414,870	84,961
Intercompany elimination	(184,445)	(93,847)	(90,598)
	$ 1,607,447	$ 1,267,202	$ 340,245
Gross profit (in thousands) -			
Contracting Services	$ 167,277	$ 137,429	$ 29,848
Shelf Contracting	164,489	173,456	(8,967)
Oil and Gas	204,143	147,912	56,231
Intercompany elimination	(21,791)	(15,099)	(6,692)
	$ 514,118	$ 443,698	$ 70,420
Gross Margin -			
Contracting Services	24%	28%	(4 pts)
Shelf Contracting	28%	38%	(10 pts)
Oil and Gas	41%	36%	5 pts
Total company	32%	35%	(3 pts)
Number of vessels[(1)]/ Utilization[(2)] -			
Contracting Services:			
Subsea construction vessels	10/96%	9/81%	
Well operations	2/62%	2/81%	
ROVs	47/70%	37/82%	
Shelf Contracting	30/54%	25/69%	

(1)

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

(2) Average vessel utilization rate is calculated by dividing the total number of days the vessels in this category generated revenues by the total number of calendar days in the applicable period.

Intercompany segment revenues during the nine months ended September 30, 2008 and 2007 were as follows (in thousands):

	Nine Months Ended September 30, 2008	2007	Increase/ (Decrease)
Contracting Services	$ 150,465	$ 62,984	$ 87,481
Shelf Contracting	33,980	30,863	3,117
	$ 184,445	$ 93,847	$ 90,598

Intercompany segment profit during the nine months ended September 30, 2008 and 2007 was as follows (in thousands):

	Nine Months Ended September 30, 2008	2007	Increase/ (Decrease)
Contracting Services	$ 17,989	$ 3,540	$ 14,449
Shelf Contracting	3,802	11,559	(7,757)
	$ 21,791	$ 15,099	$ 6,692

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

	Nine Months Ended September 30, 2008	2007	Increase/ (Decrease)
Oil and Gas information-			
Oil production volume (MBbls)	2,380	2,750	(370)
Oil sales revenue (in thousands)	$ 235,481	$ 173,619	$ 61,862
Average oil sales price per Bbl (excluding hedges)	$ 106.39	$ 64.06	$ 42.33
Average realized oil price per Bbl (including hedges)	$ 98.94	$ 63.13	$ 35.81
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 98,475		
Change in production volume (in thousands)	(36,613)		
Total increase in oil sales revenue (in thousands)	$ 61,862		
Gas production volume (MMcf)	26,607	30,660	(4,053)
Gas sales revenue (in thousands)	$ 260,483	$ 231,761	$ 28,722
Average gas sales price per mcf (excluding hedges)	$ 10.04	$ 7.30	$ 2.74
Average realized gas price per mcf (including hedges)	$ 9.79	$ 7.56	$ 2.23
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 68,398		
Change in production volume (in thousands)	(39,676)		
Total increase in gas sales revenue (in thousands)	$ 28,722		

Total production (MMcfe)	40,888	47,161	(6,273)
Price per Mcfe	$ 12.13	$ 8.60	$ 3.53
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 495,964	$ 405,380	$ 90,584
Miscellaneous revenues[1]	3,867	9,490	(5,623)
	$ 499,831	$ 414,870	$ 84,961

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

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

	Nine Months Ended September 30,			
	2008		2007	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 68,239	$ 1.67	$ 62,223	$ 1.32
Workover	12,031	0.29	6,910	0.15
Transportation	4,687	0.11	3,525	0.07
Repairs and maintenance	16,603	0.41	9,117	0.19
Overhead and company labor	5,057	0.12	8,669	0.18
Total	$ 106,617	$ 2.60	$ 90,444	$ 1.91
Depletion expense	$ 140,381	$ 3.43	$ 146,186	$ 3.10
Abandonment	10,011	0.24	16,582	0.35
Accretion expense	9,768	0.24	8,064	0.17
Impairment	23,902	0.58	904	0.02

(1) Excludes exploration expense of $5.0 million and $5.6 million for the nine months ended September 30, 2008 and 2007, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. During the nine months ended September 30, 2008, our revenues increased by 27% as compared to the same period in 2007. Contracting Services revenues increased primarily due to strong performance from our robotics subsidiary as well as significant increased revenues from our subsea construction and well operations vessels. These increases were partially offset by increased number of out-of-service days for marine and drilling upgrades of the *Q4000*, which returned to service in June 2008. Shelf Contracting revenues increased primarily as a result of the revenue contributions from certain former Horizon assets acquired in December 2007. This increase was partially offset by lower vessel utilization related to winter seasonality and harsh weather conditions which continued into May 2008, and weather downtime related to Hurricanes *Gustav* and *Ike*.

Oil and Gas revenues increased 20% during the nine months ended September 30, 2008 as compared to the same period in 2007. The increase in oil revenues was attributable to a 57% increase in oil prices realized, net of hedges in place. The increase in gas revenues was attributable to a 29% increase in gas prices realized, net of hedges in place. These increases were partially offset by lower production as a result of temporary shut-ins caused by Hurricanes *Gustav* and *Ike*. In addition, production declines were attributable to the loss of production at the Tiger deepwater field (Green Canyon 195) in late 2007, along with a natural decline in shelf production as a result of reduction in capital allocable to shelf exploration.

Gross Profit. Gross profit during the nine months ended September 30, 2008 increased $70.4 million as compared to the same period in 2007. This increase was primarily due to higher gross profit attributable to our Oil and Gas segment as a result of higher commodity prices realized, as described above, offset partially by impairment expense of approximately $23.9 million, of which approximately $14.6 million was related to the unsuccessful development well in January 2008 on Devil s Island (Garden Banks 344) and $6.7 million was related to the Tiger deepwater field, as we expect to abandon this property earlier than planned as a result of damage caused by Hurricane *Ike*. In addition, gross profit for Oil and Gas segment was negatively impacted by temporary production shut-ins in September 2008 as a result of the hurricanes.

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In addition, Contracting Services gross profit increased 22% due to the factors stated above, However, Contracting Services gross margin decreased by four points. The decline in gross margin was primarily due to lower margins realized on certain international deepwater pipelay projects during the second quarter as services were provided to the customer under various change orders; however, no revenue was recognized associated with this work as certain revenue recognition criteria were not met at September 30, 2008. Gross margin for the third quarter of 2008 improved to 27% as compared to 22% in second quarter 2008 as we continue to get work performed under various change orders approved by our customers.

These increases were partially offset by decreased Shelf Contracting gross profit. This decrease was attributable to lower vessel utilization referred to above and increased depreciation and amortization as a result of assets purchased in the Horizon acquisition. The utilization impact from the continued harsh weather in the Gulf of Mexico during the first five months of 2008 and and adverse weather condition thereafter was compounded by CDI s increased exposure in terms of its fleet size following the Horizon acquisition.

Gain on Sale of Assets, Net. Gain on sale of assets, net, increased by $53.5 million during the nine months ended September 30, 2008 as compared to the same prior year period. The increase was primarily due to a gain of $91.6 million related to the sale of a 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron blocks 371 and 381). Offsetting this gain was a loss of $11.9 million related to the sale of all our interest in our Onshore Properties. Included in the cost basis of our Onshore Properties was $8.1 million of goodwill allocated from our Oil and Gas segment. In addition, during third quarter 2007, we recognized approximately $18.8 million gain related to the sale of the Phoenix oilfield as described above.

Selling and Administrative Expenses. Selling and administrative expenses for the nine months ended September 30, 2008 were $36.3 million higher than the same prior year period. The increase was due primarily to higher overhead (primarily related to the Horizon acquisition) to support our growth. In addition, we recognized approximately $7.4 million of expenses related to the separation agreements between the Company and two of our former executive officers.

Equity in Earnings of Investments. Equity in earnings of investments increased by $16.7 million during the nine months ended September 30, 2008 as compared to the same prior year period. This increase was partially due to a $8.6 million increase in equity in earnings related to our 20% investment in Independence Hub which began production during the third quarter of 2007. Also, in second quarter 2007 equity losses and a related non-cash asset impairment charge both totaling $11.8 million from CDI s 40% investment in OTSL were recorded. These increases were partially offset by a $0.5 million decrease in equity earnings related to our investment in Deepwater Gateway as major infrastructure damage was sustained to the downstream pipeline facilities connected to the platform, causing temporary production shut-ins.

Net Interest Expense and Other. We reported net interest and other expense of $68.2 million for the nine months ended September 30, 2008 as compared to $40.8 million in the same prior year period. Gross interest expense of $95.0 million during the nine months ended September 30, 2008 was higher than the $70.3 million incurred in 2007 due to overall higher levels of indebtedness as a result of our Senior Unsecured Notes and CDI s term loan, which both closed in December 2007. Offsetting the increase in interest expense was $30.6 million of capitalized interest and $2.2 million of interest income in the first nine months of 2008, compared with $20.7 million of capitalized interest and $7.7 million of interest income in the same prior year period.

Provision for Income Taxes. Income taxes were $154.4 million during the nine months ended September 30, 2008 compared with $111.7 million in the same prior year period. The increase was primarily due to increased profitability. In addition, the effective tax rate of 38% for the nine months ended September 30, 2008 was higher than the 34% for the same prior year period. The effective tax rate for the first nine months of 2008 was higher because of the additional deferred tax expense recorded as a result of the increase in the equity earnings of CDI in excess of our tax basis. Further, the allocation of goodwill to the cost basis for the Onshore Properties sale is not allowable for tax purposes. In addition, the surrender of the tax losses related to our oil and gas subsidiary in the United Kingdom to other profitable subsidiaries in the United Kingdom that are taxed at a lower rate also contributed to the increase in our consolidated effective tax rate. These increases were partially offset by the increased benefit derived from the Internal Revenue Code §199 manufacturing deduction primarily related to oil and gas production and the effect of lower tax rates in certain foreign jurisdictions.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	September 30, 2008	December 31, 2007
Net working capital	$ 109,832	$ 48,290
Long-term debt[(1)]	1,815,083	1,725,541

(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.

	Nine Months Ended September 30,	
	2008	2007
Net cash provided by (used in):		
Operating activities	$ 339,086	$ 280,528
Investing activities	$(495,167)	$(415,720)
Financing activities	$ 103,252	$ (21,907)

Our primary cash needs are to fund capital expenditures to allow the growth of our current lines of business and to repay outstanding borrowings and make related interest payments. Historically, we have funded our capital program, including acquisitions, with cash flows from operations, borrowings under credit facilities and use of project financing along with other debt and equity alternatives.

In May 2008, as provided by our amended Senior Credit Facilities, we increased our Revolving Credit Facility by $120 million. As a result, our total borrowing capacity is now $420 million. As of September 30, 2008, we had $221.5 million of available borrowing capacity under our credit facilities. In addition, CDI had $293.8 million of available borrowing under its revolving credit facility. We do not have access to any unused portion of CDI s revolving credit facility. See Notes to Condensed Consolidated Financial Statements (Unaudited) Note 8 Long-term Debt for additional information related to our long-term obligations.

In light of the current credit crisis, in October 2008, we drew down an additional $175 million on our Revolving Credit Facility to ensure adequate and readily available liquidity. After this draw down, we have approximately $44 million of additional capacity remaining under our Revolving Credit Facility. We expect to use the proceeds from this draw down to fund:

§ critical capital projects that are ongoing during fourth quarter 2008 and into 2009;

- general corporate and operating needs as we bring our oil and gas production back online; and
- hurricane repair work (as we do not expect to begin receiving insurance proceeds until fourth quarter 2008).

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In accordance with the Senior Unsecured Notes, amended Senior Credit Facilities, Convertible Senior Notes, MARAD Debt and Cal Dive s credit facility, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, annual working capital and debt-to-equity requirements. As of September 30, 2008 and December 31, 2007, we were in compliance with these covenants and restrictions. The Senior Unsecured Notes and Senior Credit Facilities contain provisions that limit our ability to incur certain types of additional indebtedness.

The Convertible Senior Notes can be converted prior to the stated maturity under certain triggering events specified in the indenture governing the Convertible Senior Notes. To the extent we do not have long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. During the third quarter of 2008, no conversion triggers were met.

Pursuant to the documents governing our convertible preferred stock, in the event our common stock price on any date is less than a certain minimum price, we must deliver notice that either (i) the conversion price will be reset to such minimum price or (ii) in the event the holder exercises its redemption rights, we will satisfy our redemption obligations either in cash, or in a combination of cash and common stock with the number of shares of common stock, determined based upon the current market price of our common stock, subject to a maximum number of shares that can be delivered. In the event our redemption obligation is triggered and our obligation cannot be fully satisfied with common stock, we will be required to redeem a portion of the preferred stock in cash. As of October 30, 2008, our stock price has not been below the minimum price since the issuance of the preferred stock.

Working Capital

Cash flow from operating activities increased by $58.6 million in the nine months ended September 30, 2008 as compared to the same period in 2007. This increase was primarily due to higher profitability and lower income taxes paid in the first nine months of 2008 of approximately $97.1 million compared to approximately $179.1 million in the first nine months of 2007, most of which ($126.6 million) was related to the proceeds received from the CDI initial public offering in December 2006. These increases were partially offset by $37.7 million incurred in the nine months ended September 30, 2008 for recertification costs relating to regulatory drydocks as compared to $32.8 million for the same prior year period. The increase in regulatory drydocks were primarily related to the *Q4000*.

Our working capital at September 30, 2008 has improved significantly compared to end of second quarter 2008. Under the terms of the MARAD Debt, we are required to maintain positive working capital as of the end of each fiscal year. In the event that our working capital on December 31, 2008 is negative, under the terms of MARAD Debt agreements we would be required to deposit with the trustee an amount of cash determined pursuant to the agreements (the Title XI Reserve Fund) within 120 days after the year end. The Title XI Reserve Fund is calculated based on our after tax earnings, adjusted for depreciation, multiplied by a percentage equal to the original cost basis in the Q4000 divided by our total fixed assets as of December 31. This Title XI Reserve Fund is available, under conditions imposed by MARAD, for use in future periods for payment of interest and principal due under the indenture. If this deposit is required, we estimate the aggregate deposit to be between $10 million to $15 million. We believe internally generated cash flow and borrowings under our existing credit facilities will provide the necessary capital to fund our working capital requirements. This is evident by the draw-down of our Revolving Credit Facility in October 2008.

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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 nine months ended September 30, 2008 and 2007 were as follows (in thousands):

	Nine Months Ended September 30,	
	2008	**2007**
Capital expenditures:		
Contracting Services	$ (228,680)	$ (182,674)
Shelf Contracting	(70,750)	(26,390)
Production Facilities	(91,034)	(68,471)
Oil and Gas	(338,339)	(407,118)
Acquisition of business, net of cash acquired		(10,066)
Sale of short-term investments		285,395
Investments in equity investments	(708)	(16,132)
Distributions from equity investments, net[1]	4,636	6,363
Proceeds from sales of properties	230,261	4,343
Other	(553)	(970)
Cash used in investing activities	$ (495,167)	$ (415,720)

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

Restricted Cash

As of September 30, 2008 and December 31, 2007, we had $35.4 million and $34.8 million, respectively, of restricted cash. All of our restricted cash was related to funds required to be escrowed to cover decommissioning liabilities associated with the SMI 130 acquisition in 2002 by our Oil and Gas segment. We had fully satisfied the escrow requirement as of September 30, 2008. We may use the restricted cash for decommissioning the related field.

Equity Investments

We made the following contributions to our equity investments during the nine months ended September 30, 2008 and 2007 (in thousands):

Nine Months Ended September 30,

	2008	2007
Independence	$	$ 12,475
Other	708	3,656
Total	$ 708	$ 16,131

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We received the following distributions from our equity investments during the nine months ended September 30, 2008 and 2007 (in thousands):

	Nine Months Ended September 30,	
	2008	2007
Deepwater Gateway	$ 16,500	$ 20,500
Independence	16,400	6,000
Total	$ 32,900	$ 26,500

Sale of Oil and Gas Properties

In March and April 2008, we sold a total 30% working interest in the Bushwood discoveries (Garden Banks Blocks 463, 506 and 507) and other Outer Continental Shelf oil and gas properties (East Cameron blocks 371 and 381), in two separate transactions to affiliates of private independent oil and gas company for total cash consideration of approximately $181.2 million (which includes the purchasers share of past capital expenditures on these fields), and additional potential cash payments of up to $20 million based upon certain field production milestones. The new co-owners will also pay their pro rata share of all future capital expenditures related to the exploration and development of these fields. The assumption of certain decommissioning liabilities will be satisfied on a pro rata share basis between the new co-owners and us. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million in the first half of 2008.

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

Outlook

We anticipate capital expenditures for the remainder of 2008 will range from $160 million to $180 million. Our projected capital expenditures on certain projects have increased as compared to the initially budgeted amounts due primarily to scope changes, escalating costs for certain materials and services due to increasing demand, and the weakening of the U.S. dollar earlier in 2008 with respect to foreign currency denominated construction contracts. We may increase or decrease these plans based on various economic factors. We believe internally generated cash flow and borrowings under our existing credit facilities will provide the necessary capital to fund our 2008 initiatives.

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The following table summarizes our contractual cash obligations as of September 30, 2008 and the scheduled years in which the obligations are contractually due (in thousands):

	Total(1)	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes(2)	$ 300,000	$	$	$	$ 300,000
Senior Unsecured Notes	550,000				550,000
Term Loan	420,174	4,326	8,652	407,196	
MARAD debt	123,449	4,214	9,069	9,997	100,169
Revolving Credit Facility	175,000		175,000		
CDI Term Loan	335,000	80,000	160,000	95,000	
Loan notes	5,000	5,000			
Interest related to long-term debt(3)	781,948	114,978	210,589	184,081	272,300
Preferred stock dividends(4)	2,475	2,475			
Drilling and development costs	108,700	108,700			
Property and equipment(5)	74,000	74,000			
Operating leases(6)	191,524	64,459	83,431	31,706	11,928
Total cash obligations	$ 3,067,270	$ 458,152	$ 646,741	$ 727,980	$ 1,234,397

(1) Total exposure under letters of credit outstanding at September 30, 2008 was approximately $43.3 million and was excluded from the table above. These letters of credit primarily guarantee various contract bidding, contractual performance and insurance activities and shipyard commitments.

(2) Maturity 2025. Can be converted prior to stated

maturity if closing sale price of Helix s common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share) and under certain triggering events as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. At September 30, 2008, the conversion trigger was not met.

(3) Estimated interest

payments related to our long-term debt were calculated based on their respective maturity dates.

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

(5) Costs incurred as of September 30, 2008 and additional property and equipment commitments (excluding capitalized interest) at September 30, 2008 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Estimated Project Cost Range
Caesar conversion	$ 148,000	$ 8,000	$ 200,000 - 220,000
Well Enhancer construction	140,000	46,000	200,000 - 220,000
Helix Producer I[(a)]	194,000	20,000	325,000 - 355,000
Total	$ 482,000	$ 74,000	$ 725,000 - 795,000

(a) Represents 100% of the cost of the vessel, conversion and construction of additional facilities, of which we expect our portion to range between $283 million and $313 million.

(6) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at September 30, 2008 were approximately $150.9 million.

Contingencies

In orders from the MMS dated December 2005 and May 2006, we received notice from the MMS that lease price thresholds were exceeded for 2004 oil and gas production and for 2003 gas production, and that royalties are due on such production notwithstanding the provisions of the DWRRA. In a subsequent order from the MMS dated September 2008, the MMS notified us that lease thresholds were exceeded for oil and gas production for 2005, 2006 and 2007. As of September 30, 2008, we have approximately $67.3 million accrued for the related royalties and interest. On October 30, 2007, the federal district court in the Kerr-McGee case entered judgment in favor of Kerr-McGee and held that the Department of the Interior exceeded its authority by including the price thresholds in the subject leases. The government filed a notice of appeal of that decision on December 21, 2007. See Notes to

Condensed Consolidated Financial Statements (Unaudited) Note 18 for a detailed description of this contingency.

During the fourth quarter of 2006, Horizon received a tax assessment from the SAT, the Mexican taxing authority, for approximately $23 million related to fiscal 2001, including penalties, interest and monetary correction. The SAT s assessment claims unpaid taxes related to services performed among the Horizon subsidiaries that CDI acquired at the time it acquired Horizon. CDI believes under the Mexico and United States double taxation treaty that these services are not taxable and that the tax assessment itself is invalid. On February 14, 2008, CDI received notice from the SAT upholding the original assessment. On April 21, 2008, CDI filed a petition in Mexico tax court disputing the assessment. We believe that CDI s position is supported by law and CDI intends to vigorously defend its position. However, the ultimate outcome of this litigation and CDI s potential liability from this assessment, if any, cannot be determined at this time. Nonetheless, an unfavorable outcome with respect to the Mexico tax assessment could have a material adverse effect on CDI s and our financial position and results of operations. Horizon s 2002 through 2007 tax years remain subject to examination by the appropriate governmental agencies for Mexico tax purposes, with 2002 through 2004 currently under audit.

We sustained damage to certain of our oil and gas production facilities in Hurricane *Ike*. We carry comprehensive insurance on all of our operated and non-operated producing and non-producing properties which is subject to approximately $6 million of aggregate deductibles. As of September 2008, we have reached our aggregate deductibles. We believe our comprehensive coverage is sufficient to cover all our repair and inspection costs and capital redrill or rebuild costs as a result of damages sustained by the hurricane. These costs will be recorded as incurred. Insurance reimbursements will be recorded when the realization of the claim for recovery of a loss is deemed probable**.**

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. Due to the adoption of SFAS No. 157, we have updated our critical accounting policies fair value measurement. Please read the following discussion in conjunction with our Critical Accounting Policies and Estimates as disclosed in our 2007 Form 10-K.

Fair Value Measurement

SFAS No. 157 provides enhanced guidance for using fair value to measure assets and liabilities. We adopted the provisions of SFAS No. 157 on January 1, 2008 for assets and liabilities not subject to the deferral and expect to adopt this standard for all other assets and liabilities by January 1, 2009. SFAS No. 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1. Observable inputs such as quoted prices in active markets;

Level 2. Inputs, other than the quoted prices in active markets, that are observable either directly or indirectly; and

Level 3. Unobservable inputs in which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques noted in SFAS No. 157. The valuation techniques are as follows:

(a) *Market Approach*. Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

(b) *Cost Approach*. Amount that would be required to replace the service capacity of an asset (replacement cost).

(c) *Income Approach*. Techniques to convert expected future cash flows to a single present amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

The financial assets and liabilities that are recognized based on fair value on a recurring basis at September 30, 2008 include our oil and gas costless collars, interest rate swaps and foreign currency forwards. The following table provides additional details regarding the significant inputs used in the calculation of the fair values:

Item	Fair Value Hierarchy	Valuation Technique	Significant Inputs
Oil swaps and collars	Level 2	Income	Hedged oil price NYMEX sweet crude oil forward price Light surface crude oil volatility rate
Gas swaps and collars	Level 2	Income	Hedged gas price NYMEX natural gas forward price Natural gas volatility rate
Interest rate swaps	Level 2	Income	Fixed rate Three months LIBOR forward rate
Foreign currency forwards	Level 2	Income	Hedged rate Spot exchange rate Forward exchange rate calculated by adjusting the spot exchange rate by the prevailing interest differential between the currencies

As the financial assets and liabilities listed above qualify for hedge accounting, and as long as these instruments continue to be effective hedges, changes to the significant inputs described above would not have a material impact on results of operations as the change in the fair value is recorded in accumulated other comprehensive income, a component of shareholders equity. In addition, changes to significant inputs would not have a material impact on our liquidity, however, they may have a material impact on our financial condition.

Recently Issued Accounting Principles

In March 2008, the FASB issued SFAS No. 161, which applies to all derivative instruments and related hedged items accounted for under SFAS No. 133. SFAS No. 161 asks entities to provide qualitative disclosures about the objectives and strategies for using derivatives, quantitative data about the fair value of and gains and losses on derivative contracts, and details of credit-risk-related contingent features in their hedged positions. The standard is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged, but not required. We are currently evaluating the impact of this statement on our disclosures.

In May 2008, the FASB issued FSP APB 14-1. This FSP would require the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount would be amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. The effective date of FSP APB 14-1 is for fiscal years beginning after December 15, 2008 and requires retrospective application to all periods reported (with the cumulative effect of the change reported in retained earnings as of the beginning of the first period presented). The FSP does not permit early application. This FSP

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changes the accounting treatment for our Convertible Senior Notes. FSP APB 14-1 will increase our non-cash interest expense for our past and future reporting periods. In addition, it will reduce our long-term debt and increase our stockholder s equity for the past reporting periods. We are currently evaluating the potential impact of this issue on our consolidated financial statements.

In June 2008, the FASB issued FSP EITF 03-6-1. This FSP would require unvested share-based payment awards containing non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) to be included in the computation of basic EPS according to the two-class method. The effective date of FSP EITF 03-6-1 is for fiscal years beginning after December 15, 2008 and requires all prior-period EPS data presented to be adjusted retrospectively (including interim financial statements, summaries of earnings, and selected financial data) to conform with the provisions of this FSP. The FSP does not permit early application. This FSP changes our calculation of basic and diluted EPS and will lower previously reported basic and diluted EPS as weighted-average shares outstanding used in the EPS calculation will increase. We are currently evaluating the impact of this statement on our consolidated financial statements.

Also in June 2008, the FASB issued EIFT 07-5. This issue addresses the determination of whether an instrument (or an embedded feature) is indexed to an entity s own stock. This issue is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application by an entity that has previously adopted an alternative accounting policy is not permitted. We are currently evaluating the impact of this issue on our consolidated financial statements.

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.

Interest Rate Risk. As of September 30, 2008, including the effects of interest rate swaps, approximately 33% of our outstanding debt was based on floating rates. As a result, we are subject to interest rate risk. In September 2006, effective October 3, 2006, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to interest payments on $200 million of our Term Loan. In addition, in April 2008, CDI entered into an interest rate swap to stabilize cash flows relating to its interest payments on $100 million of the CDI term loan. Excluding the portion of our consolidated debt for which we have interest rate swaps in place, the interest rate applicable to our remaining variable rate debt may rise, increasing our interest expense. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $1.5 million and $4.7 million in interest expense for the three and nine months ended September 30, 2008, respectively. For the three and nine months ended September 30, 2007, we would have incurred an additional $2.6 million and $7.7 million in interest expense, respectively.

Commodity Price Risk. As of September 30, 2008, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 2,155 MBbl of oil and 18,076,400 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
October 2008 - December 2008	Collar	30 MBbl	$ 60.00 $82.35
October 2008 - December 2008	Swap	42 MBbl	$106.25
October 2008 - December 2009	Forward Sale	129 MBbl	$71.82
Natural Gas:			
January 2009 - December 2009	Forward Sale	1,506,367 MMBtu	$8.23

Subsequent to September 30, 2008, we entered into two additional natural gas costless collars and two natural gas swaps. The costless collars cover an average of 1,029,000 MMBtu per month at an average price of $7.00 to $7.90 per MMBtu for the period from January to December 2009. The swaps cover an average of 1,500,000 MMBtu per month at an average price of $7.02 per MMBtu for November and December 2008. We also entered into an oil costless collar for an average of 50.2 MBbl per month for the period from January to June 2009 at a price of $75.00 to $89.55.

Foreign Currency Exchange Risk. 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 a shipyard contract where the contractual payments are denominated in euros and expected cash outflows relating to certain vessel charters denominated in British pounds. The aggregate fair value of the foreign currency forwards as of September 30, 2008 and December 31, 2007 was a net asset (liability) of ($1.4) million and $1.4 million, respectively.

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 September 30, 2008. 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 September 30, 2008 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We implemented an enterprise resource planning system on January 1, 2008 for Helix Subsea Construction, Inc. (excluding our ROV and trencher business) and our U.S. Well Operations division and continue to evolve our controls accordingly. Resulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for the fiscal quarter ended September 30, 2008. However, this ongoing implementation effort may lead to our making additional changes in our internal controls over financial reporting in future fiscal periods. On December 11, 2007, our majority owned subsidiary, Cal Dive International, Inc., completed the acquisition of Horizon Offshore, Inc. Cal Dive continues to integrate Horizon s historical internal controls over financial reporting into their own internal controls over financial reporting within our overall control structure. This ongoing integration may lead to our making additional changes in our internal controls over financial reporting in future fiscal periods.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 18 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

Item 1A. Risk Factors

In addition to the risk factors disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007, we add the following risk factor as a result of recent events.

Economic conditions could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions and the condition of the oil and gas industry. Recent disruptions in the credit markets and concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices, both of which have contributed to a decline in our stock price and corresponding market capitalization. Further stock price or commodity price decreases in the fourth quarter could result in noncash impairments of long-lived assets and goodwill. At September 30, 2008, we had $1.1 billion of goodwill recorded in conjunction with past business combinations and $6.3 million of intangible assets with indefinite useful lives.

Continued market deterioration could also jeopardize the performance of certain counterparty obligations, including those of our insurers, customers and financial institutions. Although we monitor the creditworthiness of our counterparties, the current disruptions could lead to sudden changes in the counterparty s liquidity. In the event any such party fails to perform, our financial results could be adversely affected and we could incur losses and our liquidity could be negatively impacted.

The consequences of a prolonged recession may include a lower level of economic activity, decreased offshore exploration and drilling and increased uncertainty regarding energy prices and the capital and commodity markets. A lower level of offshore exploration and drilling could have a material adverse effect on the demand for our services. In addition a general decline in the level of economic activity might result in lower commodity prices, which may also adversely affect our revenues. In addition, the capital and credit markets have become increasingly volatile. If the capital and credit markets continue to experience volatility and the availability of funds remains limited, we may incur increased costs associated with any additional financing we may require for future operations. All of these risks, including our dependence on the oil and gas industry, and in particular the willingness of oil and gas companies to make capital expenditures, are discussed in greater detail in Item 1A. Risk Factors in the 2007 Annual Report on Form 10-K.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum value of shares that may yet be purchased under the program
July 1 to July 31, 2008[1]	7,559	$ 37.71		$ N/A
August 1 to August 31, 2008[1]				N/A
September 1 to September 30, 2008[1]	15,165	30.36		N/A

22,724	$	32.80	$	N/A

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

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Item 6. Exhibits

15.1 Independent Registered Public Accounting Firm s Acknowledgement Letter[1]

31.1 Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Chief Executive Officer[1]

31.2 Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Anthony Tripodo, Chief Financial Officer[1]

32.1 Certification of Helix s Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes Oxley Act of 2002[2]

99.1 Report of Independent Registered Public Accounting Firm[1]

(1) Filed herewith

(2) Furnished herewith

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SIGNATURES

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

		HELIX ENERGY SOLUTIONS GROUP, INC. **(Registrant)**
Date: October 31, 2008	By:	**/s/ Owen Kratz**
		Owen Kratz President and Chief Executive Officer
Date: October 31, 2008	By:	**/s/ Anthony Tripodo**
		Anthony Tripodo Executive Vice President and Chief Financial Officer

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