HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
August 01, 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 June 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 July 28, 2008, 91,857,500 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)

	June 30, 2008 (Unaudited)	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,148	$ 89,555
Accounts receivable		
Trade, net of allowance for uncollectible accounts of $4,321 and $2,874, respectively	402,936	447,502
Unbilled revenue	34,431	10,715
Costs in excess of billing	75,370	53,915
Other current assets	162,199	125,582
Total current assets	698,084	727,269
Property and equipment	4,530,881	4,088,561
Less accumulated depreciation	(994,829)	(843,873)
	3,536,052	3,244,688
Other assets:		
Equity investments	202,501	213,429
Goodwill	1,084,711	1,089,758
Other assets, net	213,097	177,209
	$ 5,734,445	$ 5,452,353
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 324,961	$ 382,767
Accrued liabilities	246,567	221,366
Income taxes payable	95,688	
Current maturities of long-term debt	163,656	74,846
Total current liabilities	830,872	678,979
Long-term debt	1,697,797	1,725,541
Deferred income taxes	599,458	625,508
Decommissioning liabilities	185,828	193,650
Other long-term liabilities	68,550	63,183
Total liabilities	3,382,505	3,286,861

Minority interest	275,121	263,926
Convertible preferred stock	55,000	55,000
Commitments and contingencies		
Shareholders equity:		
Common stock, no par, 240,000 shares authorized, 91,867 and 91,385 shares issued, respectively	769,834	755,758
Retained earnings	1,234,783	1,069,546
Accumulated other comprehensive income	17,202	21,262
Total shareholders equity	2,021,819	1,846,566
	$ 5,734,445	$ 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 June 30,	
	2008	**2007**
Net revenues:		
Contracting services	$ 346,333	$ 268,492
Oil and gas	194,161	142,082
	540,494	410,574
Cost of sales:		
Contracting services	252,269	182,464
Oil and gas	95,811	86,345
	348,080	268,809
Gross profit	192,414	141,765
Gain on sale of assets, net	18,803	5,684
Selling and administrative expenses	43,921	33,388
Income from operations	167,296	114,061
Equity in earnings (losses) of investments	6,155	(4,748)
Net interest expense and other	18,668	14,286
Income before income taxes	154,783	95,027
Provision for income taxes	55,925	33,261
Minority interest	7,076	3,119
Net income	91,782	58,647
Preferred stock dividends	880	945
Net income applicable to common shareholders	$ 90,902	$ 57,702
Earnings per common share:		
Basic	$ 1.00	$ 0.64
Diluted	$ 0.96	$ 0.61
Weighted average common shares outstanding:		
Basic	90,519	90,047

Diluted	95,928	95,991

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

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

	Six Months Ended June 30,	
	2008	**2007**
Net revenues:		
Contracting services	$ 626,019	$ 533,580
Oil and gas	365,212	273,049
	991,231	806,629
Cost of sales:		
Contracting services	472,455	360,519
Oil and gas	205,483	168,730
	677,938	529,249
Gross profit	313,293	277,380
Gain on sale of assets, net	79,916	5,684
Selling and administrative expenses	91,705	63,988
Income from operations	301,504	219,076
Equity in earnings of investments	17,078	1,356
Net interest expense and other	44,714	27,298
Income before income taxes	273,868	193,134
Provision for income taxes	99,557	66,384
Minority interest	7,313	11,338
Net income	166,998	115,412
Preferred stock dividends	1,761	1,890
Net income applicable to common shareholders	$ 165,237	$ 113,522
Earnings per common share:		
Basic	$ 1.83	$ 1.26
Diluted	$ 1.75	$ 1.21
Weighted average common shares outstanding:		
Basic	90,511	90,021

Diluted	95,652	95,262

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

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

	Six Months Ended June 30,	
	2008	**2007**
Cash flows from operating activities:		
Net income	$ 166,998	$ 115,412
Adjustments to reconcile net income to net cash provided by (used in) operating activities		
Depreciation, depletion and amortization	170,820	143,462
Asset impairment charge	17,028	904
Equity in losses of investments, inclusive of impairment charge	2,304	10,865
Amortization of deferred financing costs	2,503	1,522
Stock compensation expense	13,552	7,472
Deferred income taxes	(23,064)	36,477
Excess tax benefit from stock-based compensation	(2,567)	(432)
Gain on sale of assets	(79,916)	(5,684)
Minority interest	7,313	11,338
Changes in operating assets and liabilities:		
Accounts receivable, net	14,342	3,501
Other current assets	3,141	93
Margin deposits	(73,200)	
Income tax payable	107,142	(162,044)
Accounts payable and accrued liabilities	(74,889)	3,655
Other noncurrent, net	(61,178)	(42,850)
Net cash provided by operating activities	190,329	123,691
Cash flows from investing activities:		
Capital expenditures	(554,800)	(431,482)
Sale of short-term investments		275,395
Investments in equity investments	(708)	(15,265)
Distributions from equity investments, net	9,118	6,279
Proceeds from sales of property	229,243	4,339
Other	(400)	(687)
Net cash used in investing activities	(317,547)	(161,421)
Cash flows from financing activities:		
Repayment of Helix Term Notes	(2,163)	(4,200)
Borrowings on Helix Revolver	541,500	
Repayments on Helix Revolver	(444,500)	
Repayment of MARAD borrowings	(1,982)	(1,888)
Borrowings on CDI Revolver	32,500	6,600
Repayments on CDI Revolver	(23,000)	(67,600)

Repayments on CDI Term Notes	(40,000)	
Deferred financing costs	(1,709)	(88)
Capital lease payments		(1,249)
Preferred stock dividends paid	(1,761)	(1,890)
Repurchase of common stock	(3,223)	(3,969)
Excess tax benefit from stock-based compensation	2,567	432
Exercise of stock options, net	2,138	802
Net cash provided by (used in) financing activities	60,367	(73,050)
Effect of exchange rate changes on cash and cash equivalents	444	906
Net decrease in cash and cash equivalents	(66,407)	(109,874)
Cash and cash equivalents:		
Balance, beginning of year	89,555	206,264
Balance, end of period	$ 23,148	$ 96,390

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 June 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 in 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, the 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

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assets of Cal Dive International, Inc. and its subsidiaries (Cal Dive or CDI). Our ownership in CDI was approximately 58.2% as of June 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 June 30, 2008 and December 31, 2007, we had $35.2 million and $34.8 million, respectively, of restricted cash. Almost 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 Others Assets, Net. We had fully satisfied the escrow requirement as of June 30, 2008. We may use the restricted cash for decommissioning the related field.

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

	Six Months Ended June 30,	
	2008	**2007**
Interest paid	$33,747	$ 49,709
Income taxes paid	$15,480	$191,950

Non-cash investing activities for the six months ended June 30, 2008 included $19.5 million of accruals for capital expenditures. Non-cash investing activities for the six months ended June 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 9 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.

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 estimated preliminary fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Cash	$ 170,607
Other current assets	157,137
Property and equipment	351,147
Goodwill	258,083
Intangible assets[1]	9,510
Other long-term assets	15,270
Total assets acquired	$ 961,754
Current liabilities	$ 176,388
Long-term debt	87,641
Deferred income taxes	67,501
Other non-current liabilities	100
Total liabilities assumed	$ 331,630
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 June 30, 2008, the net carrying amount for these intangible assets was $6.6 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.

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

	Three Months Ended June 30, 2007	Six Months Ended June 30, 2007
Net revenues	$523,465	$1,002,087
Income before income taxes	82,395	179,251
Net income	51,729	103,757
Net income applicable to common shareholders	50,784	101,867
Earnings per common share:		
Basic	$ 0.56	$ 1.13
Diluted	$ 0.54	$ 1.09

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 six months ended June 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 Well Ops SEA Pty Ltd. Acquisition

In October 2006, we acquired a 58% interest in Seatrac Pty Ltd. (Seatrac) for total consideration of approximately $12.7 million (including $0.2 million of transaction costs), with approximately $9.1 million paid to existing Seatrac shareholders and $3.4 million for subscription of new Seatrac shares. We renamed this entity Well Ops SEA Pty Ltd. (WOSEA). WOSEA is a subsea well intervention and engineering services company located in Perth, Australia. Under the terms of the purchase agreement, we had an option to purchase the remaining 42% of the entity for approximately $10.1 million. On July 1, 2007, we exercised this option and now own 100% of the entity. In addition, the agreement with the existing shareholders provides for an earnout period of five years from July 1, 2007. If during this five-year period WOSEA achieves certain financial performance objectives, the shareholders will be entitled to additional consideration of approximately $5.8 million. For the period from July 1, 2007 to June 30, 2008, the performance objectives were not reached, hence no additional consideration was paid. This purchase was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair value, with the excess being recorded as goodwill. The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at July 1, 2007 (in thousands):

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Cash and cash equivalents	$ 2,307
Other current assets	3,730
Property and equipment	7,937
Goodwill	13,682
Total assets acquired	$ 27,656
Accounts payable and accrued liabilities	$ 3,723
Deferred income taxes	960
Other non-current liabilities	241
Total liabilities assumed	$ 4,924
Net assets acquired	$ 22,732

The allocation of the purchase price was finalized on June 30, 2008. The results of WOSEA have been included in the accompanying consolidated statements of operations in our Contracting Services segment since the date of our respective purchases. Pro forma combined operating results for the six months ended June 30, 2007 are not provided because the pre-acquisition results related to WOSEA were immaterial to the historical results of the Company.

Note 6 Oil and Gas Properties

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

As of June 30, 2008, we capitalized approximately $19.1 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 June 30, 2008 and December 31, 2007 (in thousands):

	June 30, 2008	**December 31, 2007**
Huey	$ 11,556	$ 11,556
Castleton (part of Gunnison)	7,071	7,071
Other	486	469
Total	$ 19,113	$ 19,096

As of June 30, 2008, the exploratory well costs for Castleton and Huey had been capitalized for longer than one year. We are not the operator of Castleton.

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

	2008

Beginning balance at January 1,	$ 19,096
Additions pending the determination of proved reserves	735
Reclassifications to proved properties	(734)
Credit to dry hole expense	16
Ending balance at June 30,	$ 19,113

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Delay rental and geological and geophysical costs	$ 1,438	$ 2,988	$ 3,378	$ 4,052
Dry hole expense	36	(10)	(16)	116
Total exploration expense	$ 1,474	$ 2,978	$ 3,362	$ 4,168

On March 31, 2008, we agreed to sell 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), in two separate transactions to affiliates of a private independent oil and gas company for total cash consideration of approximately $181.2 million (which includes 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. The assumption of certain decommissioning liabilities will be satisfied on a pro rata share basis between the new co-owners and us. We received $120.8 million related to the sale of a 20% working interest and related to the reimbursement of capital expenditures on these fields from the purchasers. We have also received $60.4 million for the 10% sale in the second quarter 2008. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million (of which $61.1 million was recognized in first quarter 2008).

In May 2008, we sold all our interests in our onshore proved and unproved oil and gas properties located in the states of Texas, Mississippi, Louisiana, Oklahoma, New Mexico and Wyoming (Onshore Properties) to an unrelated investor. We sold these Onshore Properties for cash proceeds of $47.2 million and recorded a related loss of $11.9 million in the second quarter of 2008. Included in the cost basis of the Onshore Properties was an $8.1 million allocation of goodwill from our Oil and Gas segment. 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 first half of 2008. Costs incurred as of December 31, 2007 of $20.9 million related to this well were charged to income in 2007.

Note 7 Details of Certain Accounts (in thousands)

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

	June 30, 2008	December 31, 2007
Other receivables	$ 10,824	$ 6,733
Prepaid insurance	2,281	21,133
Other prepaids	26,104	14,922
Current deferred tax assets	14,359	13,810
Insurance claims to be reimbursed	7,018	10,173
Gas imbalance	7,036	6,654
Inventory	36,445	29,925
Income tax receivable		8,838
Margin deposits	50,563	
Other	7,569	13,394
	$ 162,199	$ 125,582

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

	June 30, 2008	December 31, 2007
Restricted cash	$ 35,198	$ 34,788
Margin deposits	22,637	
Deposits	3,419	8,417
Deferred drydock expenses, net	83,970	47,964
Deferred financing costs	38,793	39,290
Intangible assets with definite lives, net	18,568	22,216
Intangible asset with indefinite life	7,043	7,022
Contract receivables		14,635
Other	3,469	2,877
	$ 213,097	$ 177,209

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

	June 30, 2008	December 31, 2007
Accrued payroll and related benefits	$ 31,494	$ 50,389
Royalties payable	36,880	21,974
Current decommissioning liability	23,829	23,829
Unearned revenue	8,500	1,140
Billings in excess of costs	6,861	20,403
Insurance claims to be reimbursed	7,018	14,173
Accrued interest	34,637	7,090
Accrued severance(1)	2,561	14,786
Deposit	17,000	13,600
Hedge liability	28,054	10,308
Other	49,733	43,674
	$ 246,567	$ 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 June 30, 2008 was related to the separation of two of our former executive officers from the Company (See Note 17 Resignation of Executive Officers).

Note 8 Equity Investments

As of June 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 $108.6 million and $112.8 million as of June 30, 2008 and December 31, 2007, respectively, and was included in our Production Facilities segment.

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 $90.6 million and $95.7 million as of June 30, 2008 and December 31, 2007, respectively (including capitalized interest of $6.0 million and $6.2 million at June 30, 2008 and December 31, 2007, respectively), and was included in our Production Facilities segment.

Note 9 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 $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 June 30, 2008, we had outstanding $115.0 million in borrowings under our Revolving Loans and $28.8 million of unsecured letters of credit, and there were $276.2 million available under the 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 six months ended June 30, 2008 and 2007 was approximately 5.7% and 7.3%, 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 six months ended June 30, 2008 was approximately 5.8%.

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 11 Hedging Activities below.

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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 June 30, 2008, CDI had $335.0 million of term loan outstanding and $9.5 million in borrowings under its revolving credit facility. In addition, CDI had $22.1 million of unsecured letters of credit outstanding with $268.4 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 six months ended June 30, 2008 and 2007, CDI s average interest rate was 6.2%.

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 11 Hedging 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. In second quarter 2008, the closing sale price of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on June 30, 2008 exceeded 120% of the conversion price (i.e., exceeded $38.56 per share). As a result, pursuant to the terms of the indenture, the Convertible Senior Notes can be converted during the third quarter of 2008. We expect to have approximately $210 million available capacity under our Revolving Loans to cover the conversion during the third quarter 2008 (the conversion period). As a result, $210 million of the Convertible Senior Notes remained in long-term debt and $90 million was reclassified to current maturities of long-term debt. If in future quarters the conversion price trigger is met and we do not have alternative long-term financing or commitments available to cover the conversion (or a portion thereof), the portion uncovered would be classified as a current liability in the accompanying balance sheet.

Approximately 1.2 million and 965,000 shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the three and six months ended June 30, 2008, respectively, and approximately 1.6 million shares and 977,000 shares for the three and six months ended June 30, 2007, respectively, because our average share price for the respective periods was above the conversion price of approximately $32.14 per share. 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 June 30, 2008 and December 31, 2007, $125.5 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 June 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

On June 19, 2007, Kommandor LLC entered into a term loan agreement (Nordea Loan Agreement) with Nordea Bank Norge ASA. Pursuant to the Nordea Loan Agreement, the lenders will make available to Kommandor LLC up to $45.0 million pursuant to a secured term loan facility. Kommandor LLC will use all amounts borrowed under the facility to repay its existing subordinated indebtedness for the long-term financing of the Vessel and to fund expenses and fees related to the conversion of such Vessel to operate as a floating production unit. Kommandor LLC expects this borrowing to occur in the fourth quarter of 2008 upon the delivery of the Vessel after its initial conversion, and at such time, in accordance with the provisions of FIN 46, 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. As of June 30, 2008, we had $7.2 million of unsecured letters of credit outstanding under this facility. 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 $38.8 million and $39.3 million are included in Other Assets, Net as of June 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 June 30, 2008 were as follows (in thousands):

	Helix Term Loan	Helix Revolving Loans	CDI Term Loan	CDI Revolving Loans	Senior Unsecured Notes	Convertible Senior Notes(2)	MARAD Debt	Other(1)	Total
Less than one year	$ 4,326	$	$ 60,000	$	$	$ 90,000	$ 4,112	$ 5,218	$ 163,656
One to two years	4,326		80,000				4,318		88,644
Two to three years	4,326		80,000				4,533		88,859
Three to four years	4,326	115,000	80,000			210,000	4,760		414,086
Four to five years	4,326		35,000	9,500			4,997		53,823
Over five years	399,625				550,000		102,760		1,052,385
Long-term debt	421,255	115,000	335,000	9,500	550,000	300,000	125,480	5,218	1,861,453
	(4,326)		(60,000)			(90,000)	(4,112)	(5,218)	(163,656)

Current maturities									
Long-term debt, less current maturities	$ 416,929	$ 115,000	$ 275,000	$ 9,500	$ 550,000	$ 210,000	$ 121,368	$	$ 1,697,797

(1) Includes $5 million loan provided by Kommandor RØMØ to Kommandor LLC and capital leases of $0.2 million.

(2) Maturity 2025. Can be converted prior to stated maturity. In second quarter 2008, the conversion trigger was met, so the notes can be converted during third quarter 2008. As of June 30, 2008, we have approximately $210 million available to cover the conversion during the third quarter 2008 (the conversion period). As

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a result, $210 million of the Convertible Senior Notes remained in long-term debt (with the same maturity as the Revolving Loans) and $90 million was reclassified to current maturities of long-term debt. If in future quarters the conversion price trigger is met and we do not have alternative long-term financing or commitments available to cover the conversion (or a portion thereof), the portion uncovered would be classified as a current liability in the accompanying balance sheet.

Our total exposure under letters of credit outstanding at June 30, 2008 was approximately $53.3 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 six months ended June 30, 2008 and 2007 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
Interest expense	$ 29,692	$ 23,153	$ 64,575	$ 46,246
Interest income	(586)	(1,933)	(1,628)	(6,575)
Capitalized interest	(9,602)	(6,396)	(20,573)	(11,799)
Interest expense, net	$ 19,504	$ 14,824	$ 42,374	$ 27,872

Note 10 Income Taxes

The effective tax rate for the six months ended June 30, 2008 and June 30, 2007 was 36.4% and 34.4%, respectively. The effective tax rate for the first half of 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; and

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

These increases were partially offset by the increased benefit derived from the Internal Revenue Code §199 manufacturing deduction as it primarily related to oil and gas production and the effect of lower tax rates in certain foreign jurisdictions.

We believe our recorded assets and liabilities are reasonable; however, tax laws and regulations are subject to interpretation and tax litigation is inherently uncertain; therefore our assessments can involve a series of complex judgments about future events and rely heavily on estimates and assumptions. See detailed description related to a tax assessment in Note 19 Commitments and Contingencies below.

Note 11 Hedging Activities

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

Commodity Hedges

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. All of these qualify for hedge accounting. The aggregate fair value of the hedge instruments was a net liability of $23.7 million and $8.1 million as of June 30, 2008 and December 31, 2007, respectively. We recorded unrealized losses of approximately $6.6 million and $10.1 million, net of tax benefit of $3.5 million and $5.5 million during the three and six months ended June 30, 2008, respectively, in accumulated other comprehensive income, a component of shareholders equity, as these hedges were highly effective. For the three and six months ended June 30, 2007, we recorded unrealized gains (losses) of approximately $4.7 million and $(3.6)

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million, net of tax expense (benefit) of $2.5 million and $(1.9) million during the three and six months ended June 30, 2007, respectively, During the three and six months ended June 30, 2008, we reclassified approximately $15.1 million and $19.1 million of losses from other comprehensive income to net revenues upon the sale of the related oil and gas production. For the three and six months ended June 30, 2007, we reclassified approximately $0.2 million and $2.3 million of gains from other comprehensive income to net revenues.

As of June 30, 2008, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 2,475 MBbl of oil and 29,605,800 MMbtu of natural gas:

Production Period		Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:				
				$60.00
July 2008	December 2008	Collar	30 MBbl	$82.38
July 2008	December 2008	Swap	40 MBbl	$107.02
July 2008	December 2009	Forward Sale	114,167 MBbl	$71.84
Natural Gas:				
				$7.50
July 2008	December 2008	Collar	375,000 MMBtu	$11.22
July 2008	December 2009	Forward Sale	1,519,767 MMBtu	$8.26

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.

Interest Rate Hedges

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.

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 interest rate swap is charged to earnings or accumulated other comprehensive income.

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. The interest rate swaps were effective as of October 3, 2006. These interest rate swaps qualified for hedge accounting. See -Note 9 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 FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, (SFAS No. 133). On January 31, 2008, we re-designated these swaps as cash flow hedges with respect to our outstanding LIBOR-based debt. During the three months ended March 31, 2008, we recognized $1.8 million of unrealized losses as other expense, net of taxes of $1.0 million as a result of the change in fair value of our interest rate swaps from January 1, 2008 to January 31, 2008, the date of re-designation. As of June 30, 2008, these swaps continued to be highly effective. Immaterial ineffectiveness was

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recorded in income related to the period from February 1, 2008 to June 30, 2008. No ineffectiveness was recognized during the three and six months ended June 30, 2007. As of June 30, 2008 and December 31, 2007, the aggregate fair value of the derivative instruments was a net liability of $5.9 million and $4.7 million, respectively. During the three and six months ended June 30, 2008 and 2007, we reclassified approximately $0.3 million and $0.7 million of losses, respectively, from other comprehensive income to interest expense. During the three and six months ended June 30, 2007, we reclassified approximately $0.1 million and $0.2 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 June 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 $1.3 million as of June 30, 2008.

Foreign Currency Hedge

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 following table provides details related to the remaining forward contracts at June 30, 2008 (amounts in thousands):

Forecasted Settlement Date	Amount	Exchange Rate
July 31, 2008	£ 581	1.9263 (a)(b)
August 27, 2008	698	1.5593 (c)(d)
August 29, 2008	£ 581	1.9225 (a)(b)
September 26, 2008	1,344	1.5569 (c)(b)
September 29, 2008	465	1.5567 (c)(d)
December 15, 2008	3,500	1.5508 (c)(b)
March 2, 2009	1,075	1.5456 (c)(b)

(a) Related to our vessel charter payments denominated in British pounds.

(b) Designated as hedges and qualify for hedge accounting at June 30, 2008.

(c) Related to our shipyard contract where the contractual payments are denominated in euros.

(d)

Derivatives were not designated as hedges at June 30, 2008.

The aggregate fair value of the foreign currency forwards described above was a net asset of $0.2 million and $1.4 million as of June 30, 2008 and December 31, 2007, respectively.

Note 12 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:

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

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

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

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

	Level 1	**Level 2**	**Level 3**	**Total**	**Valuation Technique**
Assets:					
Foreign currency forwards		154		154	(c)
Interest rate swap		1,311		1,311	(c)
Total		1,465		1,465	
Liabilities:					
Oil and gas swaps and collars		23,712		23,712	(c)
Interest rate swaps		5,916		5,916	(c)
Total		29,628		29,628	

Note 13 Comprehensive Income

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2008	**2007**	**2008**	**2007**
Net income	$ 91,782	$ 58,647	$ 166,998	$ 115,412
Foreign currency translation gain	1,985	4,078	2,792	4,715
Unrealized gain (loss) on hedges, net	(4,405)	6,098	(6,852)	(2,091)
Total comprehensive income	$ 89,362	$ 68,823	$ 162,938	$ 118,036

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

	June 30, 2008	December 31, 2007
Cumulative foreign currency translation adjustment	$ 31,052	$ 28,260
Unrealized loss on hedges, net	(13,850)	(6,998)
Accumulated other comprehensive income	$ 17,202	$ 21,262

Note 14 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 six months ended June 30, 2008 and 2007 were as follows (in thousands):

	Three Months Ended June 30, 2008		Three Months Ended June 30, 2007	
	Income	**Shares**	**Income**	**Shares**
Earnings applicable per common share Basic	$ 90,902	90,519	$ 57,702	90,047
Effect of dilutive securities:				
Stock options		367		383
Restricted shares		210		284
Employee stock purchase plan		2		19
Convertible Senior Notes		1,199		1,627
Convertible preferred stock	880	3,631	945	3,631
Earnings applicable per common share Diluted	$ 91,782	95,928	$ 58,647	95,991

	Six Months Ended June 30, 2008		Six Months Ended June 30, 2007	
	Income	**Shares**	**Income**	**Shares**
Earnings applicable per common share Basic	$ 165,237	90,511	$ 113,522	90,021
Effect of dilutive securities:				
Stock options		384		375
Restricted shares		161		227
Employee stock purchase plan				32
Convertible Senior Notes		965		976
Convertible preferred stock	1,761	3,631	1,890	3,631
Earnings applicable per common share Diluted	$ 166,998	95,652	$ 115,412	95,262

There were no antidilutive stock options in the three and six months ended June 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 six months ended June 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 15 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 half of 2008, we granted 507,597 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, which 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 $41.10 and $41.50, respectively. There were no stock option grants in the six months ended June 30, 2008 and 2007.

Compensation cost is recognized over the respective vesting periods on a straight-line basis. For the three and six months ended June 30, 2008, $0.3 million and $0.9 million, respectively, was recognized as compensation expense related to stock options (of which $0.1 million and $0.6 million for the three and six months ended June 30, 2008, respectively, was related to the acceleration of unvested options per the separation agreements between the Company and two of our former executive officers). For the three and six months ended June 30, 2008, $4.5 million and $11.5 million, respectively, was recognized as compensation expense related to restricted shares and restricted stock units (of which $1.2 million and $2.4 million, respectively, was related to the CDI Incentive Plan and $0.5 million and $3.6 million, respectively, was related to the accelerated vesting of restricted shares per the separation agreements between the Company and two of our former executive officers). For the three and six months ended June 30, 2007, $3.0 million and $5.9 million, respectively, was recognized as compensation expense related to restricted shares (of which $0.5 million and $1.0 million, respectively, was related to the CDI Incentive Plan). Future compensation cost associated with unvested restricted stock awards at June 30, 2008 totaled approximately $49.7 million, of which approximately $15.2 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 six months ended June 30, 2008, we recognized $0.6 million and $1.1 million, respectively, of compensation expense related to the ESPP and the CDI ESPP (of which $0.3 million and $0.6 million, respectively, of expense was related to the CDI ESPP that became effective third quarter 2007). For the three and six months ended June 30, 2007, we recognized $0.5 million and $1.0 million, respectively, of compensation expense related to the ESPP.

Note 16 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 FASB Interpretation No. 46, *Consolidation of Variable Interest Entities* (FIN 46) and is included in our Production Facilities segment.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Revenues				
Contracting Services	$ 228,351	$ 154,719	$ 412,140	$ 292,436
Shelf Contracting	171,970	135,258	316,541	284,484
Oil and Gas	194,161	142,082	365,212	273,049
Intercompany elimination	(53,988)	(21,485)	(102,662)	(43,340)
Total	$ 540,494	$ 410,574	$ 991,231	$ 806,629
Income from operations				
Contracting Services	$ 37,993	$ 31,987	$ 58,904	$ 55,082
Shelf Contracting	29,498	36,142	37,046	84,445
Production Facilities equity investments(1)	(156)	(145)	(294)	(332)
Oil and Gas	104,202	48,685	214,119	87,902
Intercompany elimination	(4,241)	(2,608)	(8,271)	(8,021)
Total	$ 167,296	$ 114,061	$ 301,504	$ 219,076
Equity in losses of OTSL, inclusive of impairment	$	$ (11,793)	$	$ (10,841)
Equity in earnings of equity investments excluding OTSL	$ 6,155	$ 7,045	$ 17,078	$ 12,197

(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.

	June 30,	December 31,

	2008	2007
Identifiable Assets		
Contracting Services.	$ 1,358,720	$ 1,177,431
Shelf Contracting	1,184,077	1,274,050
Production Facilities	427,432	366,634
Oil and Gas	2,764,216	2,634,238
Total	$ 5,734,445	$ 5,452,353

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Contracting Services	$ 42,718	$ 16,901	$ 85,041	$ 31,497
Shelf Contracting	11,270	4,584	17,621	11,843
Total	$ 53,988	$ 21,485	$ 102,662	$ 43,340

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Contracting Services	$ 2,979	$ 657	$ 5,892	$ 2,675
Shelf Contracting	1,262	1,951	2,379	5,346
Total	$ 4,241	$ 2,608	$ 8,271	$ 8,021

Note 17 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. In June 2008, we recognized approximately $1.5 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. In July 2008, we recognized an additional $0.5 million of consulting expense related to a consulting agreement between the Company and Mr. Pursell.

Note 18 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 $5.7 million and $11.2 million in the three and six months ended June 30, 2008, respectively, and $5.7 million and $11.7 million in the three and six months ended June 30, 2007, respectively.

Note 19 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 $165 million and $185 million, of which approximately $124 million had been incurred, with an additional $31.7 million committed, at June 30, 2008. The *Caesar* is expected to be completed in the fourth quarter of 2008.

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 first quarter 2009. At June 30, 2008, we had incurred approximately $137 million, with an additional $43.4 million committed to this project.

Further, we, along with Kommandor RØMØ, a Danish corporation, formed a joint venture called Kommandor LLC to convert a ferry vessel into a floating production unit to be named the *Helix Producer I* (the Vessel). The total cost of the ferry and the conversion is estimated to range between $130 million and $150 million which will be funded through project financing of $45 million, with the remaining amount funded through equity contributions from the partners. The partners will guarantee the project financing

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on a several basis, with each partner providing a guarantee of $22.5 million. 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 fourth quarter 2008, we will charter the Vessel from Kommandor LLC, and will install, at 100% our cost, processing facilities and a disconnectable fluid transfer system on the Vessel for use on our Phoenix field. The cost of these additional facilities is approximately $135 million and the work is expected to be completed in second quarter 2009. As of June 30, 2008, approximately $221 million of costs related to the purchase of the Vessel ($20 million), conversion of the Vessel and construction of the additional facilities had been incurred, with an additional $54.7 million committed. Kommandor LLC qualified as a variable interest entity under FIN 46. We determined that we were the primary beneficiary of Kommandor LLC and thus have consolidated the financial results of Kommandor LLC as of June 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 weakening of the U.S. dollar with respect to foreign denominated contracts. In addition, as of June 30, 2008, we have also committed approximately $94.8 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. 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 June 30, 2008 and December 31, 2007 was approximately $62.1 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.

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 FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (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.

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.

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

	As of June 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 2,837	$ 4,163	$ 16,148	$	$ 23,148
Accounts receivable, net	73,136	169,137	270,223	241	512,737
Other current assets	76,562	108,694	47,834	(70,891)	162,199
Total current assets	152,535	281,994	334,205	(70,650)	698,084
Intercompany	144,846	51,929	(176,459)	(20,316)	
Property and equipment, net	148,949	2,164,490	1,225,382	(2,769)	3,536,052
Other assets:					
Equity investments	3,195,861	35,203	202,501	(3,231,064)	202,501
Goodwill		749,670	335,316	(275)	1,084,711
Other assets, net	54,257	62,055	125,949	(29,164)	213,097
	$ 3,696,448	$ 3,345,341	$ 2,046,894	$ (3,354,238)	$ 5,734,445
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities:					
Accounts payable	$ 52,625	$ 161,354	$ 110,941	$ 41	$ 324,961
Accrued liabilities	66,588	106,550	76,852	(3,423)	246,567
Income taxes payable	(8,478)	106,221	4,723	(6,778)	95,688
Current maturities of long-term debt	94,326		130,025	(60,695)	163,656

Total current liabilities	205,061	374,125	322,541	(70,855)	830,872
Long-term debt	1,291,929		431,353	(25,485)	1,697,797
Deferred income taxes	148,837	284,320	178,148	(11,847)	599,458
Decommissioning liabilities		181,660	4,168		185,828
Other long-term liabilities	1,573	64,584	7,152	(4,759)	68,550
Due to parent	(37,028)	72,878	37,028	(72,878)	
Total liabilities	1,610,372	977,567	980,390	(185,824)	3,382,505
Minority interest				275,121	275,121
Convertible preferred stock	55,000				55,000
Shareholders equity	2,031,076	2,367,774	1,066,504	(3,443,535)	2,021,819
	$ 3,696,448	$ 3,345,341	$ 2,046,894	$ (3,354,238)	$ 5,734,445

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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

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

	Three Months Ended June 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 90,099	$ 247,465	$ 262,870	$ (59,940)	$ 540,494
Cost of sales	84,747	133,457	184,640	(54,764)	348,080
Gross profit	5,352	114,008	78,230	(5,176)	192,414
Gain on sale of assets, net		18,594	209		18,803
Selling and administrative expenses	6,400	14,618	23,836	(933)	43,921
Income from operations	(1,048)	117,984	54,603	(4,243)	167,296
Equity in earnings (losses) of investments	101,727	(215)	6,155	(101,512)	6,155
Net interest expense and other	(117)	11,205	6,948	632	18,668
Income before income taxes	100,796	106,564	53,810	(106,387)	154,783
Provision for income taxes	5,861	37,524	14,284	(1,744)	55,925
Minority interest				7,076	7,076
Net income	94,935	69,040	39,526	(111,719)	91,782
Preferred stock dividends	880				880
Net income applicable to common shareholders	$ 94,055	$ 69,040	$ 39,526	$ (111,719)	$ 90,902

	Three Months Ended June 30, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 35,201	$ 197,230	$ 204,816	$ (26,673)	$ 410,574
Cost of sales	29,077	124,476	138,935	(23,679)	268,809
Gross profit	6,124	72,754	65,881	(2,994)	141,765
Gain on sale of assets, net	221	2,175	3,288		5,684
Selling and administrative expenses	5,547	12,260	15,968	(387)	33,388
Income from operations	798	62,669	53,201	(2,607)	114,061
Equity in earnings (losses) of investments	65,229	2,988	(4,748)	(68,217)	(4,748)
Net interest expense and other	(931)	11,479	3,738		14,286
Income before income taxes	66,958	54,178	44,715	(70,824)	95,027
Provision for income taxes	1,576	18,216	14,326	(857)	33,261

Minority interest			13	3,106	3,119
Net income	65,382	35,962	30,376	(73,073)	58,647
Preferred stock dividends	945				945
Net income applicable to common shareholders	$ 64,437	$ 35,962	$ 30,376	$ (73,073)	$ 57,702

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

	Six Months Ended June 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 174,990	$ 449,707	$ 481,241	$ (114,707)	$ 991,231
Cost of sales	150,861	271,208	360,295	(104,426)	677,938
Gross profit	24,129	178,499	120,946	(10,281)	313,293
Gain on sale of assets, net		79,707	209		79,916
Selling and administrative expenses	17,295	29,077	47,367	(2,034)	91,705
Income from operations	6,834	229,129	73,788	(8,247)	301,504
Equity in earnings of investments	184,116	5,157	17,078	(189,273)	17,078
Net interest expense and other	6,377	24,468	15,703	(1,834)	44,714
Income before income taxes	184,573	209,818	75,163	(195,686)	273,868
Provision for income taxes	14,469	71,050	17,365	(3,327)	99,557
Minority interest				7,313	7,313
Net income	170,104	138,768	57,798	(199,672)	166,998
Preferred stock dividends	1,761				1,761
Net income applicable to common shareholders	$ 168,343	$ 138,768	$ 57,798	$ (199,672)	$ 165,237

	Six Months Ended June 30, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Net revenues	$ 90,884	$ 363,099	$ 405,792	$ (53,146)	$ 806,629
Cost of sales	66,979	236,716	269,953	(44,399)	529,249
Gross profit	23,905	126,383	135,839	(8,747)	277,380
Gain on sale of assets, net	221	2,175	3,288		5,684
Selling and administrative expenses	11,740	22,533	30,446	(731)	63,988
Income from operations	12,386	106,025	108,681	(8,016)	219,076
Equity in earnings of investments	118,367	6,055	1,356	(124,422)	1,356
Net interest expense and other	(3,284)	22,737	7,845		27,298
Income before income taxes	134,037	89,343	102,192	(132,438)	193,134
Provision for income taxes	8,694	28,807	31,687	(2,804)	66,384
Minority interest			113	11,225	11,338

Net income	125,343		60,536		70,392		(140,859)		115,412
Preferred stock dividends	1,890								1,890
Net income applicable to common shareholders	$ 123,453	$	60,536	$	70,392	$	(140,859)	$	113,522

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

	Six Months Ended June 30, 2008				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income	$ 170,104	$ 138,768	$ 57,798	$ (199,672)	$ 166,998
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates			2,304		2,304
Equity in earnings of affiliates	(184,116)	(5,157)		189,273	
Other adjustments	75,295	(44,031)	(414)	(9,823)	21,027
Net cash provided by operating activities	61,283	89,580	59,688	(20,222)	190,329
Cash flows from investing activities:					
Capital expenditures	(48,121)	(335,468)	(171,211)		(554,800)
Investments in equity investments			(708)		(708)
Distributions from equity investments, net			9,118		9,118
Proceeds from sales of property		228,483	760		229,243
Other		(400)			(400)
Net cash used in investing activities	(48,121)	(107,385)	(162,041)		(317,547)
Cash flows from financing activities:					
Borrowings on revolver	541,500		32,500		574,000
Repayments on revolver	(444,500)		(23,000)		(467,500)
Repayments of debt	(2,163)		(41,982)		(44,145)
Deferred financing costs	(1,709)				(1,709)
Preferred stock dividends paid	(1,761)				(1,761)
Repurchase of common stock	(3,223)				(3,223)
Excess tax benefit from stock-based compensation	2,567				2,567
Exercise of stock options, net	2,138				2,138
Intercompany financing	(106,681)	19,359	67,100	20,222	
	(13,832)	19,359	34,618	20,222	60,367

Net cash provided by (used in) financing activities					
Effect of exchange rate changes on cash and cash equivalents			444		444
Net increase (decrease) in cash and cash equivalents	(670)	1,554	(67,291)		(66,407)
Cash and cash equivalents:					
Balance, beginning of year	3,507	2,609	83,439		89,555
Balance, end of period	$ 2,837	$ 4,163	$ 16,148	$	$ 23,148

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

	Six Months Ended June 30, 2007				
	Helix	Guarantors	Non-Guarantors	Consolidating Entries	Consolidated
Cash flow from operating activities:					
Net income	$ 125,343	$ 60,536	$ 70,392	$ (140,859)	$ 115,412
Adjustments to reconcile net income to net cash provided by (used in) operating activities:					
Equity in losses of unconsolidated affiliates			10,865		10,865
Equity in earnings of affiliates	(118,367)	(6,055)		124,422	
Other adjustments	(164,754)	118,130	6,532	37,506	(2,586)
Net cash provided by (used in) operating Activities	(157,778)	172,611	87,789	21,069	123,691
Cash flows from investing activities:					
Capital expenditures	(24,236)	(349,025)	(58,221)		(431,482)
Sale of short-term investments	275,395				275,395
Investments in equity investments			(15,265)		(15,265)
Distributions from equity investments, net			6,279		6,279
Proceeds from sales of property		2,003	2,336		4,339
Other		(687)			(687)
Net cash provided by (used in) investing activities	251,159	(347,709)	(64,871)		(161,421)
Cash flows from financing activities:					
Borrowings on revolver			6,600		6,600
Repayments on revolver			(67,600)		(67,600)
Repayments of debt	(4,200)		(1,888)		(6,088)
Deferred financing costs	(73)		(15)		(88)
Capital lease payments			(1,249)		(1,249)
Preferred stock dividends paid	(1,890)				(1,890)
Repurchase of common stock	(3,969)				(3,969)
Excess tax benefit from stock-based compensation	432				432
Exercise of stock options, net	802				802
Intercompany financing	(172,584)	170,369	23,284	(21,069)	

Net cash provided by (used in) financing activities	(181,482)	170,369	(40,868)	(21,069)	(73,050)
Effect of exchange rate changes on cash and cash equivalents			906		906
Net decrease in cash and cash equivalents	(88,101)	(4,729)	(17,044)		(109,874)
Cash and cash equivalents:					
Balance, beginning of year	142,489	7,690	56,085		206,264
Balance, end of period	$ 54,388	$ 2,961	$ 39,041	$	$ 96,390

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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 certain statements that are, or may be deemed to be, forward-looking statements within the meaning of 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, other than statements of historical facts, included herein or incorporated herein by reference are forward-looking statements. Included among 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 related to the volatility in commodity prices for oil and gas and in the supply of and demand for oil and natural gas or the ability to replace oil and gas reserves;
- 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 regarding any financing transactions or arrangements, our ability to enter into such transactions or our ability to comply with covenants or restrictions;
- statements relating to the construction or acquisition of vessels or equipment, including statements concerning the engagement of any engineering, procurement and construction contractor 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;
- statements regarding any Securities and Exchange Commission (SEC) or other governmental or regulatory inquiry or investigation;
- statements regarding anticipated legislative, governmental, regulatory, administrative or other public body actions, requirements, permits or decisions;
- statements regarding anticipated developments, industry trends, performance or industry ranking;
- statements related to the underlying assumptions related to any projection or forward-looking statement;
- statements related to environmental risks, exploration and development risks, or drilling and operating risks;
- statements related to the ability of the Company to retain key members of its senior management and key employees;

statements regarding general economic or political conditions, whether international, national or in the regional and local market areas in which we are doing business; and

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

These forward-looking statements are often identified by the use of terms and phrases such as achieve, anticipate, believe, estimate, expect, forecast, plan, project, propose, strategy, predict, envision, hope, in potential, achieve, should, could and similar terms and phrases. Although we believe that the expectations reflected these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. You should not place undue reliance on these forward-looking statements.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including 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. Forward-looking statements are only as of

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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.

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 in 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, the 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 58.2% as of June 30, 2008. As of June 30, 2008, our contracting services operations had backlog of approximately $1.3 billion, of which over $700 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.

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Comparison of Three Months Ended June 30, 2008 and 2007

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Increase/ (Decrease)
Revenues (in thousands) -			
Contracting Services	$ 228,351	$ 154,719	$ 73,632
Shelf Contracting	171,970	135,258	36,712
Oil and Gas	194,161	142,082	52,079
Intercompany elimination	(53,988)	(21,485)	(32,503)
	$ 540,494	$ 410,574	$ 129,920
Gross profit (in thousands) -			
Contracting Services	$ 51,049	$ 43,071	$ 7,978
Shelf Contracting	47,256	45,565	1,691
Oil and Gas	98,350	55,737	42,613
Intercompany elimination	(4,241)	(2,608)	(1,633)
	$ 192,414	$ 141,765	$ 50,649
Gross Margin -			
Contracting Services	22%	28%	(6 pts)
Shelf Contracting	27%	34%	(7 pts)
Oil and Gas	51%	39%	12 pts
Total company	36%	35%	1 pt
Number of vessels(1)/ Utilization(2) -			
Contracting Services:			
Offshore construction vessels	8/93%	7/70%	
Well operations	2/60%	2/94%	
ROVs	42/70%	34/87%	
Shelf Contracting	30/55%	25/63%	

(1) Represents number of vessels (including chartered vessels) as of the end of the period excluding acquired vessels prior to their

in-service dates, and vessels taken out of service prior to their disposition.

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

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

	Three Months Ended June 30,		
	2008	**2007**	**Increase/ (Decrease)**
Contracting Services	$ 42,718	$ 16,901	$ 25,817
Shelf Contracting	11,270	4,584	6,686
	$ 53,988	$ 21,485	$ 32,503

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

	Three Months Ended June 30, 2008	2007	Increase/ (Decrease)
Contracting Services	$ 2,979	$ 657	$ 2,322
Shelf Contracting	1,262	1,951	(689)
	$ 4,241	$ 2,608	$ 1,633

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

	Three Months Ended June 30, 2008	2007	Increase/ (Decrease)
Oil and Gas information-			
Oil production volume (MBbls)	897	938	(41)
Oil sales revenue (in thousands)	$ 94,591	$ 58,429	$ 36,162
Average oil sales price per Bbl (excluding hedges)	$ 115.57	$ 62.78	$ 52.79
Average realized oil price per Bbl (including hedges)	$ 105.48	$ 62.32	$ 43.16
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 40,463		
Change in production volume (in thousands)	(4,301)		
Total increase in oil sales revenue (in thousands)	$ 36,162		
Gas production volume (MMcf)	9,492	10,182	(690)
Gas sales revenue (in thousands)	$ 98,363	$ 81,892	$ 16,471
Average gas sales price per mcf (excluding hedges)	$ 11.00	$ 7.99	$ 3.01
Average realized gas price per mcf (including hedges)	$ 10.36	$ 8.04	$ 2.32
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 23,617		
Change in production volume (in thousands)	(7,146)		
Total increase in gas sales revenue (in thousands)	$ 16,471		
Total production (MMcfe)	14,873	15,807	(934)
Price per Mcfe	$ 12.97	$ 8.88	$ 4.09
Oil and Gas revenue information (in thousands)-			
Oil and gas sales revenue	$ 192,954	$ 140,321	$ 52,633
Miscellaneous revenues(1)	1,207	1,761	(554)
	$ 194,161	$ 142,082	$ 52,079

(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 June 30, 2008		2007	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 23,995	$ 1.61	$ 19,897	$ 1.26
Workover	3,964	0.27	1,328	0.08
Transportation	2,184	0.15	1,275	0.08
Repairs and maintenance	5,728	0.39	2,884	0.18
Overhead and company labor	1,134	0.07	3,230	0.21
Total	$ 37,005	$ 2.49	$ 28,614	$ 1.81
Depletion expense	$ 50,951	$ 3.43	$ 48,521	$ 3.07
Abandonment	2,818	0.19	2,754	0.17
Accretion expense	3,257	0.22	2,574	0.16
Impairment	306	0.02	904	0.06

(1) Excludes exploration expense of $1.5 million and $3.0 million for the three months ended June 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 June 30, 2008, our revenues increased by 32% as compared to the same period in 2007. Contracting Services revenues increased primarily due to strong performance from our robotics subsidiary as well as increased utilization of our offshore construction vessels. These increases were partially offset by increased number of out-of-service days for the marine and drilling upgrades of the *Q4000*. 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.

Oil and Gas revenues increased 37% during the three months ended June 30, 2008 as compared to the same period in 2007. The increase in oil revenues was attributable to a 69% increase in realized oil prices with slightly lower production compared with the same prior year period. The increase in gas revenues was attributable to a 29% increase in realized gas prices, partially offset by a 7% decrease in gas production in the second quarter of 2008 as compared to the same prior year period. Production declines were attributable to the loss of production at the Tiger deepwater field 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 in the second quarter of 2008 increased $50.6 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.

Further, Contracting Services gross profit increased 19% for the reasons stated above, However, Contracting Services gross margin decreased by six points. The decline in gross margin was primarily due to lower margins realized on certain international deepwater pipelay projects during the 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 June 30, 2008. We expect our Contracting Services gross margin to improve in the remainder of the year.

Shelf Contracting gross profit increased slightly during second quarter 2008 as compared to the same prior year period. The increase was primarily attributable to gross profit contributions from certain

Horizon assets, offset partially by lower vessel utilization, as described above, and higher depreciation and amortization due primarily to assets purchased in the Horizon acquisition.

Gain on Sale of Assets, Net. Gain on sale of assets, net, was $18.8 million during the three months ended June 30, 2008. In April 2008, we sold a 10% 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) for a gain of $30.5 million. This gain was partially offset by an $11.9 million loss related to the sale of all our interest in our Onshore Properties. Included in the cost basis of our Onshore Properties was $8.1 million of goodwill allocated from our Oil and Gas segment.

Selling and Administrative Expenses. Selling and administrative expenses of $43.9 million for the second quarter of 2008 were $10.5 million higher than the $33.4 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. In addition, in June 2008, we recognized approximately $1.5 million of expenses related to the separation agreement between the Company and Mr. Pursell, our former Chief Financial Officer, as a result of his resignation and the termination of his employment with the Company.

Equity in Earnings of Investments. Equity in earnings of investments increased by $10.9 million during the three months ended June 30, 2008 as compared to the same prior year period. This increase was mostly due to second quarter 2007 equity losses and a related non-cash asset impairment charge totaling $11.8 million from CDI s 40% investment in OTSL. In June 2007, CDI s investment in OTSL was reduced to zero. Our equity in earnings related to our 20% investment in Independence Hub increased $1.0 million over the same prior year period. Our investment in Deepwater Gateway contributed a $0.4 million increase in equity in earnings.

Net Interest Expense and Other. We reported net interest and other expense of $18.7 million in second quarter 2008 as compared to $14.3 million in the same prior year period. Gross interest expense of $29.7 million during the three months ended June 30, 2008 was higher than the $23.2 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 $9.6 million of capitalized interest and $0.6 million of interest income in the second quarter of 2008, compared with $6.4 million of capitalized interest and $1.9 million of interest income in the same prior year period.

Provision for Income Taxes. Income taxes increased to $55.9 million in the three months ended June 30, 2008 as compared to $33.3 million in the same prior year period. The increase was primarily due to increased profitability. In addition, the effective tax rate of 36.1% for the second quarter of 2008 was higher than the 35.0% for the second quarter of 2007. The effective tax rate for the second quarter of 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 allocation of goodwill to the cost basis for the Onshore Properties sale is not allowable for tax purposes. 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.

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Comparison of Six Months Ended June 30, 2008 and 2007

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Increase/ (Decrease)
Revenues (in thousands)			
Contracting Services	$ 412,140	$ 292,436	$ 119,704
Shelf Contracting	316,541	284,484	32,057
Oil and Gas	365,212	273,049	92,163
Intercompany elimination	(102,662)	(43,340)	(59,322)
	$ 991,231	$ 806,629	$ 184,602
Gross profit (in thousands)			
Contracting Services	$ 89,889	$ 77,565	$ 12,324
Shelf Contracting	71,946	103,517	(31,571)
Oil and Gas	159,729	104,319	55,410
Intercompany elimination	(8,271)	(8,021)	(250)
	$ 313,293	$ 277,380	$ 35,913
Gross Margin			
Contracting Services	22%	27%	(5 pts)
Shelf Contracting	23%	36%	(13 pts)
Oil and Gas	44%	38%	6 pts
Total company	32%	34%	(2 pts)
Number of vessels(1)/ Utilization(2)			
Contracting Services:			
Offshore construction vessels	8/95%	7/73%	
Well operations	2/43%	2/80%	
ROVs	42/66%	34/80%	
Shelf Contracting	30/48%	25/66%	

(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 six months ended June 30, 2008 and 2007 were as follows (in thousands):

	Six Months Ended June 30,		Increase/
	2008	**2007**	**(Decrease)**
Contracting Services	$ 85,041	$ 31,497	$ 53,544
Shelf Contracting	17,621	11,843	5,778
	$ 102,662	$ 43,340	$ 59,322

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Increase/ (Decrease)
Contracting Services	$ 5,892	$ 2,675	$ 3,217
Shelf Contracting	2,379	5,346	(2,967)
	$ 8,271	$ 8,021	$ 250

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

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007	Increase/ (Decrease)
Oil and Gas information			
Oil production volume (MBbls)	1,807	1,897	(90)
Oil sales revenue (in thousands)	$ 174,045	$ 112,482	$ 61,563
Average oil sales price per Bbl (excluding hedges)	$ 103.78	$ 59.41	$ 44.37
Average realized oil price per Bbl (including hedges)	$ 96.33	$ 59.31	$ 37.02
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ 70,224		
Change in production volume (in thousands)	(8,661)		
Total increase in oil sales revenue (in thousands)	$ 61,563		
Gas production volume (MMcf)	19,594	20,152	(558)
Gas sales revenue (in thousands)	$ 188,825	$ 157,803	$ 31,022
Average gas sales price per mcf (excluding hedges)	$ 9.92	$ 7.71	$ 2.21
Average realized gas price per mcf (including hedges)	$ 9.64	$ 7.83	$ 1.81
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ 36,393		
Change in production volume (in thousands)	(5,371)		
Total increase in gas sales revenue (in thousands)	$ 31,022		
Total production (MMcfe)	30,435	31,531	(1,096)
Price per Mcfe	$ 11.92	$ 8.57	$ 3.35
Oil and Gas revenue information (in thousands)			
Oil and gas sales revenue	$ 362,870	$ 270,285	$ 92,585
Miscellaneous revenues[(1)]	2,342	2,764	(422)
	$ 365,212	$ 273,049	$ 92,163

(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:

	Six Months Ended June 30,			
	2008		2007	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses[1]:				
Direct operating expenses[2]	$ 46,295	$ 1.52	$ 39,708	$ 1.26
Workover	6,706	0.22	4,673	0.15
Transportation	3,136	0.10	2,493	0.08
Repairs and maintenance	10,601	0.35	6,176	0.20
Overhead and company labor	3,796	0.13	5,862	0.18
Total	$ 70,534	$ 2.32	$ 58,912	$ 1.87
Depletion expense	$ 104,579	$ 3.44	$ 95,439	$ 3.03
Abandonment	3,477	0.11	4,079	0.13
Accretion expense	6,503	0.21	5,229	0.17
Impairment	17,028	0.56	904	0.03

(1) Excludes exploration expense of $3.4 million and $4.2 million for the six months ended June 30, 2008 and 2007, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Revenues. During the six months ended June 30, 2008, our revenues increased by 23% 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 offshore construction 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.

Oil and Gas revenues increased 34% during the six months ended June 30, 2008 as compared to the same period in 2007. The increase in oil revenues was attributable to a 62% increase in oil prices realized offset by slightly lower production compared to the same prior year period. The increase in gas revenues was attributable to a 23% increase in gas prices realized, partially offset by lower gas production during the first half of 2008 as compared to the same prior year period. Production declines were attributable to the loss of production at the Tiger deepwater field 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 six months ended June 30, 2008 increased $35.9 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 $17.0 million, of which approximately $14.6 million was related to the unsuccessful development well in January 2008 on Devil s Island (Garden Banks 344).

In addition, Contracting Services gross profit increased 16% due to the factors stated above, However, Contracting Services gross margin decreased by five points. The decline in gross margin was primarily due to lower margins realized on certain international deepwater pipelay projects during the 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 June 30, 2008.

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 was compounded by CDI s increased exposure in terms of fleet size following the Horizon acquisition.

Gain on Sale of Assets, Net. Gain on sale of assets, net, was $79.9 million during the six months ended June 30, 2008. We recognized 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.

Selling and Administrative Expenses. Selling and administrative expenses for the six months ended June 30, 2008 were $27.7 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 $6.9 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 $15.7 million during the six months ended June 30, 2008 as compared to the same prior year period. This increase was partially due to a $6.4 million increase in equity in earnings related to our 20% investment in Independence Hub which began production during the third quarter of 2007. Our investment in Deepwater Gateway contributed a $0.7 million increase in equity in earnings. 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.

Net Interest Expense and Other. We reported net interest and other expense of $44.7 million for the first six months of 2008 as compared to $27.3 million in the same prior year period. Gross interest expense of $64.6 million during the six months ended June 30, 2008 was higher than the $46.2 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 $20.6 million of capitalized interest and $1.6 million of interest income in the first six months of 2008, compared with $11.8 million of capitalized interest and $6.6 million of interest income in the same prior year period.

Provision for Income Taxes. Income taxes increased to $99.6 million in the first six months of 2008 as compared to $66.4 million in the same prior year period. The increase was primarily due to increased profitability. In addition, the effective tax rate of 36.4% for the six months ended June 30, 2008 was higher than the 34.4% for the same prior year period. The effective tax rate for the first six 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. 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):

	June 30, 2008	December 31, 2007
Net working capital	$ (132,788)	$ 48,290
Long-term debt[(1)]	1,697,797	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.

	Six Months Ended June 30,	
	2008	**2007**
Net cash provided by (used in):		
Operating activities	$ 190,329	$ 123,691
Investing activities	$(317,547)	$(161,421)
Financing activities	$ 60,367	$ (73,050)

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 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 June 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. In second quarter 2008, the closing sale price of our common stock for at least 20 trading days in the period of 30 consecutive trading days ending on June 30, 2008 exceeded 120% of the conversion price (i.e., exceeded $38.56 per share). As a result, pursuant to the terms of the indenture, the Convertible Senior Notes can be converted during third quarter 2008. We expect to have approximately $210 million available capacity under our Revolving Loans to cover the conversion during the third quarter 2008 (the conversion period). As a result, $210 million of the Convertible Senior Notes remained in long-term debt and $90 million was reclassified to current maturities of long-term debt.

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 June 30, 2008, we had $276.2 million of available borrowing capacity under our credit facilities. If our Senior Convertible Notes are converted during third quarter 2008 (see Senior Convertible Notes below), we expect to use our available capacity under the Revolving Loans to satisfy this obligation. In addition, CDI had $268.4 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 9 Long-term Debt for additional information related to our long-term obligations.

Working Capital

Cash flow from operating activities increased by $66.6 million in the six months ended June 30, 2008 as compared to the same period in 2007. This increase was primarily due to lower income taxes paid in the first six months of 2008 of approximately $15.5 million compared to approximately $192.0 million in the first six months of 2007, most of which ($126.6 million) was related to the proceeds received from the CDI initial public offering in December 2006. This increase was partially offset by $73.2 million increase related to margin deposits as required by various forward commodity sales contracts we have in place (see description below under Margin Deposits).

We had a net working capital deficit of $132.8 million at June 30 2008. The following items were contributing factors to this deficit:

§ A $90 million reclassification of our Senior Convertible Notes from Long-term Debt to Current Maturities of Long-term Debt as certain conversion triggers were met in the second quarter 2008 (see Note 9 Long-Term Debt). We do not expect the notes to be converted during the third quarter.

§ A $22.6 million increase in non-current margin deposits related to various forward commodity sales contracts.

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. Although we have a net working capital deficit at June 30, 2008, we believe internally generated cash flow and borrowings under our existing credit facilities will provide the necessary capital to fund our working capital requirements.

Investing Activities

Capital expenditures have consisted principally of strategic asset acquisitions related to the purchase or construction of dynamically positioned vessels, acquisition of select businesses, improvements to existing vessels, acquisition of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the six months ended June 30, 2008 and 2007 were as follows (in thousands):

	Six Months Ended June 30,	
	2008	**2007**
Capital expenditures:		
Contracting Services	$ (185,552)	$ (99,557)
Shelf Contracting	(40,875)	(12,272)
Production Facilities	(66,044)	(36,854)
Oil and Gas	(262,329)	(282,799)
Sale of short-term investments		275,395
Investments in equity investments	(708)	(15,265)
Distributions from equity investments, net(1)	9,118	6,279
Proceeds from sales of properties	229,243	4,339
Other	(400)	(687)
Cash used in investing activities	$ (317,547)	$ (161,421)

(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 June 30, 2008 and December 31, 2007, we had $35.2 million and $34.8 million, respectively, of restricted cash. Almost 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. We had fully satisfied the escrow requirement as of June 30, 2008. We may use the restricted cash for decommissioning the related field.

Margin Deposits

As of June 30, 2008, we had $73.2 million of margin deposits as related to various forward commodity sales contracts we have in place, of which $50.6 million and $22.6 million were reported in Other Current Assets and Other Assets, Net, respectively. To the extent that market prices for oil or natural gas exceed the applicable strike price or contractual price in a hedge or forward sale, the counterparty may request cash or letters of credit as collateral for exposures above specific credit thresholds established by them. Cash funded is held in an interest bearing escrow account at the counterparty s financial institution. Amounts held in escrow are returned to us as either commodity prices decline thereby reducing the counterparty s exposure, or as the underlying contracts are settled on a monthly basis. At July 31, 2008, total margin deposits under these forward commodity sales contracts were reduced to $5.8 million.

Equity Investments

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

	Six Months Ended June 30,	
	2008	2007
Independence	$	$ 12,475
Other	708	2,790
Total	$ 708	$ 15,265

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

	Six Months Ended June 30,	
	2008	2007
Deepwater Gateway	$ 14,500	$ 15,500
Independence	14,000	3,000
Total	$ 28,500	$ 18,500

Sale of Oil and Gas Properties

On March 31, 2008, we agreed to sell 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. We received $120.8 million related to the sale of a 20% working interest and the reimbursement of capital expenditures on these fields from the purchasers. We have also received $60.4 million for the 10% sale in the second quarter of 2008. Proceeds from the sale of these properties were used to pay down our outstanding revolving loans in April 2008. As a result of these sales, we recognized a pre-tax gain of $91.6 million (of which $61.1 million was recognized in first quarter 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.

Outlook

We anticipate capital expenditures for the remainder of 2008 will range from $375 million to $475 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

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due to increasing demand, and the weakening of the U.S. dollar 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.

The following table summarizes our contractual cash obligations as of June 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	$ 90,000	$	$ 210,000	$
Senior Unsecured Notes	550,000				550,000
Term Loan	421,255	4,326	8,652	8,652	399,625
MARAD debt	125,480	4,112	8,851	9,757	102,760
Revolving Credit Facility	115,000			115,000	
CDI Term Loan	335,000	60,000	160,000	115,000	
CDI Revolving Credit Facility	9,500			9,500	
Loan notes	5,000	5,000			
Capital leases	218	218			
Interest related to long-term debt[3]	779,596	110,191	199,320	180,695	289,390
Preferred stock dividends[4]	2,737	2,737			
Drilling and development costs	94,800	94,800			
Property and equipment[5]	129,800	129,800			
Operating leases[6]	130,313	56,637	44,369	11,570	17,737
Total cash obligations	$ 2,998,699	$ 557,821	$ 421,192	$ 660,174	$ 1,359,512

(1) Our total exposure under letters of credit outstanding at June 30, 2008 was approximately $53.3 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 (see Notes to Condensed Consolidated Financial Statements (Unaudited) Note 9). In second quarter 2008, the conversion trigger was met, so the notes can be converted during third quarter 2008. As of June 30, 2008, we have approximately $210 million available to cover the conversion during the third quarter 2008 (the conversion period). As a result, $210 million of the Convertible Senior Notes remained in long-term debt (with the same maturity as the Revolving Loans) and $90 million was reclassified to current maturities of long-term debt. If in future quarters the conversion price

trigger is met and we do not have alternative long-term financing or commitments available to cover the conversion (or a portion thereof), the portion uncovered would be classified as a current liability in the accompanying balance sheet.

(3) Amount includes estimated interest payment for the Convertible Senior Notes through maturity of 2025.

(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 June 30, 2008 and additional property and equipment commitments (excluding capitalized

interest) at June 30, 2008 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Estimated Project Cost Range	
Caesar conversion	$ 124,000	$ 31,700	$ 165,000	185,000
Well Enhancer construction	137,000	43,400	200,000	220,000
Helix Producer I[a]	221,000	54,700	270,000	290,000
Total	$ 482,000	$ 129,800	$ 635,000	695,000

(a) Represents 100% of the cost of the vessel, conversion and construction of additional facilities, of which we expect our portion to range between $228 million and $248 million.

(6) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at June 30, 2008 were approximately $78.1 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. As of June 30, 2008, we have approximately $62.1 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 19 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.

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 June 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 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.

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 June 30, 2008, including the effects of interest rate swaps, approximately 41.4% 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 $1.4 million and $3.2 million in interest expense for the three and six months ended June 30, 2008, respectively. For the three and six months ended June 30, 2007, we would have incurred an additional $2.5 million and $5.1 million in interest expense, respectively.

Commodity Price Risk. As of June 30, 2008, we had the following volumes under derivative and forward sale contracts related to our oil and gas producing activities totaling 2,475 MBbl of oil and 29,605,800 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
July 2008 December 2008	Collar	30 MBbl	$ 60.00 $82.38
July 2008 December 2008	Swap	40 MBbl	$ 107.02
July 2008 December 2009	Forward Sale	114,167 MBbl	$ 71.84
Natural Gas:			
July 2008 December 2008	Collar	375,000 MMBtu	$ 7.50 $11.22
July 2008 December 2009	Forward Sale	1,519,767 MMBtu	$ 8.26

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 following table provides details related to the remaining forward contracts at June 30, 2008 (amounts in thousands):

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Forecasted Settlement Date	Amount	Exchange Rate
July 31, 2008	£ 581	1.9263(a)(b)
August 27, 2008	698	1.5593(c)(d)
August 29, 2008	£ 581	1.9225(a)(b)
September 26, 2008	1,344	1.5569(c)(b)
September 29, 2008	465	1.5567(c)(d)
December 15, 2008	3,500	1.5508(c)(b)
March 2, 2009	1,075	1.5456(c)(b)

(a) Related to our vessel charter payments denominated in British pounds.

(b) Designated as hedges and qualify for hedge accounting at June 30, 2008.

(c) Related to our shipyard contract where the contractual payments are denominated in euros.

(d) Derivatives were not designated as hedges at June 30, 2008.

The aggregate fair value of the foreign currency forwards described above was a net asset of $0.2 million and $1.4 million as of June 30, 2008 and December 31, 2007, 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 June 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 June 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 June 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.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 19 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum value of shares that may yet be purchased under the program
April 1 to April 30, 2008(1)	61	$ 33.70		$ N/A
May 1 to May 31, 2008(1)	114	36.33		N/A
June 1 to June 30, 2008(1)	377	39.94		N/A
	552	$ 38.51		$ N/A

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

Item 4. Other Information

Helix s Annual Meeting of Shareholders was held on May 6, 2008. As of the close of business on March 28, 2008, the record date for the annual meeting, there were 91,680,796 shares of common stock entitled to vote, of which there were 80,488,087 (87.8%) shares present at the annual meeting in person or by proxy. At the annual meeting, stockholders voted on one matter: the election of two Class III Directors for a term of three years expiring at the 2011 Annual Meeting of Shareholders. The voting results were as follows:

Gordon F. Ahalt	For	79,429,410	Withheld	1,058,677
Anthony Tripodo(1)	For	72,433,492	Withheld	8,054,595

The two nominees for Class III Director were elected.

(1)

Anthony Tripodo resigned from our board of directors on June 25, 2008 at which date he was appointed our Chief Financial Officer.

Our Class I Directors Owen Kratz, Bernard J. Duroc-Danner and John V. Lovoi, continue in office until our 2010 Annual Meeting of Shareholders. Our Class II Directors, T. William Porter, William L. Transier and James A. Watt, continue in office until our 2009 Annual Meeting of Shareholders.

Item 6. Exhibits

4.1	Guaranty Facility Agreement effective June 30, 2008 by and among Helix Energy Solutions Group, Inc and Nordea Bank Norge ASA and its affiliate, Nordea Bank Finland Plc[(1)]
10.1	Separation Agreement by and between Helix Energy Solutions Group, Inc. and A. Wade Pursell effective June 25, 2008, incorporated by reference to Exhibit 10.1 to the Form 8-K filed with the Securities and Exchange Commission on June 30, 2008 (June 2008 8-K).
10.2	Employment Agreement by and between Helix Energy Solutions Group, Inc. and Anthony Tripodo dated June 25, 2008, incorporated by reference to Exhibit 10.2 of the June 2008 8-K.

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10.3 Consulting Agreement by and between Helix Energy Solutions Group, Inc. and A. Wade Pursell entered into July 4, 2008[1]

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

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: August 1, 2008	By: **/s/ Owen Kratz** Owen Kratz President and Chief Executive Officer
Date: August 1, 2008	By: **/s/ Anthony Tripodo** Anthony Tripodo Executive Vice President and Chief Financial Officer

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INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

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99.1 Report of Independent Registered Public Accounting Firm(1)

(1) Filed herewith

(2) Furnished herewith