HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
May 04, 2007

Table of Contents

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 March 31, 2007

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 N. Sam Houston Parkway E. 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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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 May 1, 2007, 91,307,627 shares of common stock were outstanding.

TABLE OF CONTENTS

Table of Contents

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

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

	March 31, 2007 (Unaudited)	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 183,134	$ 206,264
Short-term investments	19,575	285,395
Accounts receivable		
Trade, net of allowance for uncollectible accounts of $407 and $982, respectively	334,186	287,875
Unbilled revenue	51,445	82,834
Other current assets	62,992	61,532
Total current assets	651,332	923,900
Property and equipment	2,910,361	2,721,362
Less accumulated depreciation	(568,809)	(508,904)
	2,341,552	2,212,458
Other assets:		
Equity investments	219,720	213,362
Goodwill, net	824,137	822,556
Other assets, net	123,030	117,911
	$ 4,159,771	$ 4,290,187
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 210,688	$ 240,067
Accrued liabilities	190,694	199,650
Income tax payable	9,969	147,772
Current maturities of long-term debt	25,993	25,887
Total current liabilities	437,344	613,376
Long-term debt	1,420,764	1,454,469
Deferred income taxes	454,539	436,544
Decommissioning liabilities	139,213	138,905
Other long-term liabilities	7,343	6,143

Total liabilities	2,459,203	2,649,437
Commitments and contingencies		
Minority interest	68,525	59,802
Convertible preferred stock	55,000	55,000
Shareholders equity:		
Common stock, no par, 240,000 shares authorized, 91,302 and 90,628 shares issued, respectively	748,756	745,928
Retained earnings	808,604	752,784
Accumulated other comprehensive income	19,683	27,236
Total shareholders equity	1,577,043	1,525,948
	$ 4,159,771	$ 4,290,187

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

1

Table of Contents

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

	Three Months Ended March 31,	
	2007	**2006**
Net revenues:		
Contracting services	$ 265,088	$ 211,336
Oil and gas	130,967	80,312
	396,055	291,648
Cost of sales:		
Contracting services	178,055	131,692
Oil and gas	82,385	57,690
	260,440	189,382
Gross profit	135,615	102,266
Selling and administrative expenses	30,600	21,028
Income from operations	105,015	81,238
Equity in earnings of investments	6,104	6,236
Net interest expense and other	13,012	2,190
Income before income taxes	98,107	85,284
Provision for income taxes	33,123	29,091
Minority interest	8,219	
Net income	56,765	56,193
Preferred stock dividends	945	804
Net income applicable to common shareholders	$ 55,820	$ 55,389
Earnings per common share:		
Basic	$ 0.62	$ 0.71
Diluted	$ 0.60	$ 0.67
Weighted average common shares outstanding:		
Basic	89,994	77,969
Diluted	94,312	83,803

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

Table of Contents

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Cash flows from operating activities:		
Net income	$ 56,765	$ 56,193
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	69,885	33,226
Dry hole expense	126	20,746
Equity in earnings of investments, net of distributions		(2,803)
Amortization of deferred financing costs	728	289
Stock compensation expense	3,744	1,565
Deferred income taxes	15,992	7,789
Excess tax benefit from stock-based compensation	(187)	(6,738)
Minority interest	8,219	
Changes in operating assets and liabilities:		
Accounts receivable, net	(14,738)	(3,016)
Other current assets	10	1,702
Accounts payable and accrued liabilities	(46,734)	(29,874)
Income taxes payable	(137,259)	14,835
Other noncurrent, net	(19,605)	(6,384)
Net cash (used in) provided by operating activities	(63,054)	87,530
Cash flows from investing activities:		
Capital expenditures	(181,899)	(61,461)
Acquisition of businesses, net of cash acquired	(79)	(77,927)
Investments in equity investments	(10,294)	(11,373)
Distributions from equity investments, net	4,896	635
Sale of short-term investments, net	265,820	
Increase in restricted cash	(266)	(3,038)
Proceeds from sales of property	(383)	1,531
Net cash provided by (used in) investing activities	77,795	(151,633)
Cash flows from financing activities:		
Repayment of Senior Credit Facilities	(2,100)	
Repayment of Cal Dive International, Inc. revolving credit facility	(29,000)	
Repayment of MARAD borrowings	(1,888)	(1,798)
Deferred financing costs	(36)	(6)
Capital lease payments	(622)	(739)
Preferred stock dividends paid	(945)	(1,059)
Repurchase of common stock	(3,956)	(149)
Excess tax benefit from stock-based compensation	187	6,738

Exercise of stock options, net	376	7,729
Net cash (used in) provided by financing activities	(37,984)	10,716
Effect of exchange rate changes on cash and cash equivalents	113	140
Net decrease in cash and cash equivalents	(23,130)	(53,247)
Cash and cash equivalents:		
Balance, beginning of year	206,264	91,080
Balance, end of period	$ 183,134	$ 37,833

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

3

Table of Contents

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, 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, 2006. The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in the financial statements and the related disclosures. Actual results may differ from our estimates. Management has reflected all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes are necessary for a fair presentation of the condensed consolidated balance sheets, results of operations and cash flows, as applicable. Operating results for the period ended March 31, 2007 are not necessarily indicative of the results that may be expected for the year ending December 31, 2007. Our balance sheet as of December 31, 2006 included herein has been derived from the audited balance sheet as of December 31, 2006 included in our 2006 Annual Report on 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 2006 Annual Report on 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 development solutions and other key services (contracting services operations) to the open market as well as to our own reservoirs (oil and gas operations). Our oil and gas business is a prospect generating, exploration, development and production company. By employing our own key services and methodologies, we seek to lower finding and development costs relative to industry norms.

Contracting Services Operations

We seek to provide services and methodologies which we believe are critical to finding and developing offshore reservoirs and maximizing the economics from marginal fields. Those life of field services are organized in five disciplines: reservoir and well tech services, drilling, production facilities, construction and well operations. We have disaggregated our contracting services operations into three reportable segments in accordance with Statement of Financial Accounting Standard No. 131 *Disclosures about Segments of an Enterprise and Related Information* (SFAS No. 131): Contracting Services (which currently includes deepwater construction, well operations and reservoir and well tech services); Shelf Contracting and Production Facilities. Within our contracting services operations, we operate primarily in the Gulf of Mexico, the North Sea and Asia/Pacific regions, with services that cover the lifecycle of an offshore oil or gas field. Our Shelf Contracting segment, including the 40% interest in Offshore Technology Solutions Limited (OTSL), consists of our majority-owned subsidiary, Cal Dive International, Inc. (Cal Dive or CDI). In December 2006, Cal Dive completed an initial public offering of 22,173,000 shares of its stock. See Note 4 Initial Public Offering of Cal Dive International, Inc. below.

Table of Contents

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 and to achieve better returns than are likely to be generated through pure service contracting. Over the last 15 years we have evolved this business model to include not only mature oil and gas properties but also proved reserves yet to be developed, and most recently the properties of Remington Oil and Gas Corporation (Remington), an exploration, development and production company we acquired in July 2006. 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 March 31, 2007 and December 31, 2006, we had $33.9 million and $33.7 million, respectively, of restricted cash included in other assets, net, all of which 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 have fully satisfied the escrow requirement as of March 31, 2007. We may use the restricted cash for decommissioning the related field.

The following table provides supplemental cash flow information for the three months ended March 31, 2007 and 2006 (in thousands):

	Three Months Ended March 31,	
	2007	**2006**
Interest paid (net of capitalized interest)	$ 17,453	$1,382
Income taxes paid	$154,388	$8,823

Non-cash investing activities for the three months ended March 31, 2006 included $27.3 million of accruals for capital expenditures. Non-cash investing activities for the three months ended March 31, 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 Initial Public Offering of Cal Dive International, Inc.

In December 2006, we contributed the assets of our Shelf Contracting segment into Cal Dive International, Inc., our then wholly owned subsidiary. Cal Dive subsequently sold 22,173,000 shares of its common stock in an initial public offering and distributed the net proceeds of $264.4 million to us as a dividend. In connection with the offering, CDI also entered into a $250 million revolving credit facility. In December 2006, Cal Dive borrowed $201 million under the facility and distributed $200 million of the proceeds to us as a dividend. For additional information related to the Cal Dive credit facility, see Note 9 Long-term Debt below. We recognized an after-tax gain of $96.5 million, net of taxes of $126.6 million as a result of these transactions in 2006. We have used and plan to use the remaining proceeds for general corporate purposes.

In connection with the offering, together with CDI shares issued to CDI employees since the offering, our ownership of CDI decreased to approximately 73% as of March 31, 2007 and December 31, 2006. Subject to market conditions, we may sell additional shares of Cal Dive common stock in the future. When our ownership of Cal Dive falls below 50%, we will deconsolidate Cal Dive from our financial statements.

Further, in conjunction with the offering, the tax basis of certain of CDI s tangible and intangible assets was increased to fair value. The increased tax basis should result in additional tax deductions available to CDI over a period of two to five years. Under a Tax Matters Agreement between us and CDI, for a period of ten years from the closing of CDI s initial public offering, to the extent CDI generates taxable income sufficient to realize the additional tax deductions, it will be required to pay us 90% of the amount of tax savings actually realized from the step-up of the basis of certain assets. As of March 31, 2007 and December 31, 2006, we have a receivable from CDI of approximately $11.3 million related to the Tax Matters Agreement. For additional information related to the Tax Matters Agreement, see our 2006 Annual Report on Form 10-K.

Note 5 Acquisition of Remington Oil and Gas Corporation

On July 1, 2006, we acquired 100% of Remington, an independent oil and gas exploration and production company headquartered in Dallas, Texas, with operations concentrated in the onshore and offshore regions of the Gulf Coast, for approximately $1.4 billion in cash and stock and the assumption of $355.0 million of liabilities. The merger consideration was 0.436 of a share of our common stock and $27.00 in cash for each share of Remington common stock. On July 1, 2006, we issued 13,032,528 shares of our common stock to Remington stockholders and funded the cash portion of the Remington acquisition (approximately $806.8 million) and transaction costs (approximately $18.6 million) through borrowings under a credit agreement (see Note 9 below).

The Remington 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, with the excess being recorded in goodwill. The following table summarizes the estimated preliminary fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Current assets	$ 154,358
Property and equipment	863,935
Goodwill	708,807
Other intangible assets(1)	6,800
Total assets acquired	$ 1,733,900
Current liabilities	$ 129,957
Deferred income taxes	201,316
Decommissioning liabilities (including current portion)	21,906
Other non-current liabilities	1,800
Total liabilities assumed	$ 354,979
Net assets acquired	$ 1,378,921

(1) The intangible asset is related to a favorable drilling rig contract and to several non-compete agreements between the Company and certain members

of senior management. The fair value of the drilling rig contract was $5.0 million with $2.5 million reclassified into property and equipment for drilling of a certain successful exploratory well as of March 31, 2007. If drilling is unsuccessful on the second well of the drill rig contract, the remainder of the intangible asset will be expensed in the period drilling is determined to be unsuccessful. The fair value of the non-compete agreements was $1.8 million, which is being amortized over the term of the agreements (three years) on a straight-line basis.

The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management s review of the final valuations. The primary areas of the purchase price allocation which are not yet finalized relate to receipt of a third-party valuation report. The final valuation is expected to be completed during the second quarter of 2007.

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 the drilling is determined to be unsuccessful.

At March 31, 2007, we had capitalized approximately $78.8 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 March 31, 2007 and December 31, 2006 (in thousands):

	March 31, 2007	December 31, 2006
Huey	$ 11,464	$ 11,378
Noonan	59,856	27,824
Castleton (part of *Gunnison*)	7,070	7,070
Other	363	3,711
Total	$ 78,753	$ 49,983

As of March 31, 2007, all of these exploratory well costs had been capitalized for a period of one year or less, except for Castleton. We are not the operator of Castleton.

The following table reflects net changes in suspended exploratory well costs during the three months ended March 31, 2007 (in thousands):

	2007
Beginning balance at January 1,	$ 49,983
Additions pending the determination of proved reserves	75,119
Reclassifications to proved properties	(46,223)
Charged to dry hole expense	(126)
Ending balance at March 31,	$ 78,753

Further, the following table details the components of exploration expense for the three months ended March 31, 2007 and 2006 (in thousands):

	Three Months Ended March 31,	
	2007	2006
Delay rental	$ 26	$ 164
Geological and geophysical costs	1,038	1,195
Dry hole expense	126	20,746
Total exploration expense	$ 1,190	$ 22,105

In addition, in the three months ended March 31, 2007 and 2006, we expensed inspection and repair costs related to damages caused by Hurricanes *Katrina* and *Rita* for our oil and gas properties totaling approximately $693,000 and $3.5 million, respectively, partially offset by $2.7 million of insurance recoveries recognized in the three months ended March 31, 2006. No insurance recoveries have been received in 2007.

We agreed to participate in the drilling of an exploratory well (Tulane prospect) that was drilled in the first quarter of 2006. This prospect targeted reserves in deeper sands, within the same trapping fault system, of a currently producing well. In March 2006, mechanical difficulties were experienced in the drilling of this well, and after further review, the well was plugged and abandoned. Approximately $20.7 million was charged to earnings during the first quarter of 2006 related to this well.

Note 7 Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of March 31, 2007 and December 31, 2006:

	March 31, 2007	December 31, 2006
Other receivables	$ 7,389	$ 3,882
Prepaid insurance	13,094	17,320
Other prepaids	13,580	9,174
Current deferred tax assets	10,116	3,706
Insurance claims to be reimbursed	5,397	3,627
Hedging assets		5,202
Gas imbalance	5,561	4,739
Current notes receivable		1,500
Assets held for sale		698
Other	7,855	11,684
	$ 62,992	$ 61,532

Other assets, net, consisted of the following as of March 31, 2007 and December 31, 2006:

	March 31, 2007	December 31, 2006
Restricted cash	$ 33,943	$ 33,676
Deferred drydock expenses, net	35,604	26,405
Deferred financing costs	27,602	28,257
Intangible assets with definite lives, net	17,669	20,783
Intangible asset with indefinite life	6,935	6,922
Other	1,277	1,868
	$ 123,030	$ 117,911

Accrued liabilities consisted of the following as of March 31, 2007 and December 31, 2006:

	March 31, 2007	December 31, 2006
Accrued payroll and related benefits	$ 24,296	$ 42,381
Royalties payable	73,134	67,822
Current decommissioning liability	30,020	28,766
Insurance claims to be reimbursed	5,397	3,627
Hedging liability	5,743	184
Accrued interest	12,479	15,579
Other	39,625	41,291
	$ 190,694	$ 199,650

Note 8 Equity Investments

As of March 31, 2007, we have the following 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) (a 50/50 venture) to design, construct, install, own and operate a tension leg platform (TLP) production hub primarily for Anadarko Petroleum Corporation s *Marco Polo* field discovery in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway totaled $113.0 million and $119.3 million as of March 31, 2007 and December 31, 2006, 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. The platform attained substantial mechanical completion in March 2007. Our investment in Independence was $92.2 million and $82.7 million as of March 31, 2007 and December 31, 2006, respectively, and was included in our Production Facilities segment. Further, we are co-party to a guaranty agreement with Enterprise to the extent of our ownership in Independence. The agreement states, among other things, that Enterprise and we guarantee performance under the Independence Hub Agreement between Independence and the producers group of exploration and production companies up to $426 million, plus applicable attorneys fees and related expenses. We have estimated the fair value of our share of the guaranty obligation to be immaterial at March 31, 2007 based upon the remote possibility of payments being made under the performance guarantee.

OTSL. In July 2005, we acquired a 40% minority ownership interest in OTSL in exchange for our DP DSV, *Witch Queen*. Our investment in OTSL totaled $11.8 million and $10.9 million at March 31, 2007 and December 31, 2006, respectively, and was included in our Shelf Contracting segment. OTSL provides marine construction services to the oil and gas industry in and around Trinidad and Tobago, as well as the U.S. Gulf of Mexico. Further, in conjunction with our investment in OTSL, we provided OTSL with a one year, unsecured $1.5 million working capital loan, initially bearing interest at 6% per annum. OTSL repaid the loan and accrued interest in full in January 2007. In the first quarter of 2006, OTSL chartered the *Witch Queen* to us for certain services performed in the U.S. Gulf of Mexico. We incurred costs associated with the contract with OTSL totaling approximately $7.7 million in 2006. The charter ended in March 2006.

Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount was determined to be other than temporary. In judging other than temporary, we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and longer-term operating and financial prospects of the equity company, and our longer-term intent of retaining the investment in the entity. No impairments were recorded in the three months ended March 31, 2007 and 2006.

Note 9 Long-Term Debt

Senior Credit Facilities

On July 3, 2006, we entered into a Credit Agreement (the Credit Agreement) with Bank of America, N.A., as administrative agent and as lender, together with the other lenders (collectively, the Lenders). Under the Credit Agreement, we borrowed $835 million in a term loan (the Term Loan) and may borrow up to $300 million (the Revolving Loans) under a revolving credit facility (the Revolving Credit Facility). In addition, the Revolving Credit Facility may be used for issuances of letters of credit up to an outstanding amount of $50 million. The proceeds from the Term Loan were used to fund the cash portion of the Remington acquisition. At March 31, 2007 and December 31, 2006, $830.8 million and $832.9 million, respectively, of the Term Loan was outstanding.

The Term Loan matures on July 1, 2013 and is subject to scheduled principal payments of $2.1 million quarterly. The Revolving Loans mature on July 1, 2011. We may elect to prepay amounts outstanding under the Term Loan without prepayment penalty, but may not reborrow any amounts prepaid. We may prepay amounts outstanding under the Revolving Loans without prepayment penalty, and may reborrow amounts prepaid prior to maturity. We did not have any amount outstanding under the Revolving Loans at March 31, 2007. The Credit Agreement includes terms, conditions and covenants

Table of Contents

that we consider customary for this type of facility. As of March 31, 2007, we were in compliance with these covenants.

The Term Loan currently bears interest at the one, three or six month LIBOR at our election plus a 2.00% margin. Our interest rate on the Term loan for the three months ended March 31, 2007 was approximately 7.3% (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 Credit Agreement.

As the rates for the Term Loan are subject to market influences and will vary over the term of the agreement, we entered into various interest rate swaps for $200 million of notional value effective as of October 3, 2006. These hedges are designated as cash flow hedges and qualify for hedge accounting. Under the swaps we receive interest based on three-month LIBOR and pay interest quarterly at an average annual fixed rate of 5.131% which began in October 2006. The objective of the hedge is to eliminate the variability of cash flows in the interest payments for up to $200 million of our Term Loan. Changes in the cash flows of the interest rate swap are expected to exactly offset the changes in cash flows (i.e., changes in interest rate payments) attributable to fluctuations in LIBOR on up to $200 million of our Term Loan.

Cal Dive International, Inc. Revolving Credit Facility

In November 2006, CDI entered into a five-year $250 million revolving credit facility with certain financial institutions. The loans mature in November 2011. Loans under this facility are non-recourse to Helix. Loans under the revolving credit facility currently bear interest at the LIBOR rate plus a margin ranging from 0.625% to 1.75%. CDI s interest rate on the credit facility for the three months ended March 31, 2007 was approximately 6.2%.

The CDI credit agreement and the other documents entered into in connection with the credit agreement include terms, conditions and covenants that are customary for this type of facility. At March 31, 2007, CDI was in compliance with all these covenants.

At March 31, 2007 and December 31, 2006, CDI had outstanding debt of $172 million and $201 million, respectively, under this credit facility. CDI expects to use the remaining availability under the revolving credit facility for working capital and other general corporate purposes. We do not have access to any unused portion of CDI s revolving credit facility.

Convertible Senior Notes

On March 30, 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 (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 as specified in the indenture governing the Convertible Senior Notes. To the extent we do not have alternative long-term financing secured to cover the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. During the first quarter of 2007, no conversion triggers were met.

Approximately 179,000 shares and 1.5 million shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the three months ended March 31, 2007 and 2006, respectively, because our average share price for the respective periods was above the conversion price of approximately $32.14 per share. As a result, there would be a premium over the principal amount, which is paid in cash, and the 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 March 31, 2007 and December 31, 2006, $129.4 million and $131.3 million was outstanding on our long-term financing for construction of the *Q4000.* This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration (MARAD Debt). The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the *Q4000,* with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027). In accordance with the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of March 31, 2007, we were in compliance with these covenants.

In September 2005, we entered into an interest rate swap agreement with a bank. The swap was designated as a cash flow hedge of a forecasted transaction in anticipation of the refinancing of the MARAD Debt from floating rate debt to fixed-rate debt that closed on September 30, 2005. The interest rate swap agreement totaled an aggregate notional amount of $134.9 million with a fixed interest rate of 4.695%. On September 30, 2005, we terminated the interest rate swap and received cash proceeds of approximately $1.5 million representing a gain on the interest rate differential. This gain was deferred and is being amortized over the remaining life of the MARAD Debt as an adjustment to interest expense.

Other

In connection with the acquisition of Helix Energy Limited, we entered into a two-year note payable to the former owners totaling approximately 3.1 million British Pounds, or approximately $5.6 million, on November 3, 2005 (the balance was approximately $6.2 million at March 31, 2007 and at December 31, 2006). The note bears interest at a LIBOR based floating rate with interest payments due quarterly beginning January 1, 2006. The note is due in November 2007.

Deferred financing costs of $27.6 million and $28.3 million are included in other assets, net as of March 31, 2007 and December 31, 2006, respectively, and are being amortized over the life of the respective agreement.

Scheduled maturities of long-term debt and capital lease obligations outstanding as of March 31, 2007 were as follows (in thousands):

	Term Loan	CDI Revolving Credit Facility	Convertible Senior Notes	MARAD Debt	Loan Notes(1)	Capital Leases	Total
Less than one year	$ 8,400	$	$	$ 3,917	$ 11,157	$ 2,519	$ 25,993
One to two years	8,400			4,113		883	13,396
Two to Three years	8,400			4,318			12,718
Three to four years	8,400			4,533			12,933
Four to five years	8,400	172,000		4,760			185,160
Over five years	788,800		300,000	107,757			1,196,557
Long-term debt	830,800	172,000	300,000	129,398	11,157	3,402	1,446,757
Current maturities	(8,400)			(3,917)	(11,157)	(2,519)	(25,993)
Long-term debt, less current maturities	$ 822,400	$ 172,000	$ 300,000	$ 125,481	$	$ 883	$ 1,420,764

(1) Includes $5 million of loan provided by Kommandor RØMØ, a member in Kommandor LLC of which we own 50%, to Kommandor LLC as of March 31, 2007. The loan is expected to be repaid at the completion of the initial conversion, which is forecasted to be the end of 2007. As such, the entire loan amount is classified as current.

We had unsecured letters of credit outstanding at March 31, 2007 totaling approximately $36.5 million. These letters of credit primarily guarantee various contract bidding and insurance activities. The following table details our interest expense and capitalized interest for the three months ended March 31, 2007 and 2006 (in thousands):

	Three Months Ended March 31,	
	2007	**2006**
Interest expense	$ 23,093	$ 4,535
Interest income	(4,642)	(819)
Capitalized interest	(5,403)	(1,178)
Interest expense, net	$ 13,048	$ 2,538

The carrying amount and estimated fair value of our debt instruments, including current maturities as of March 31, 2007 and December 31, 2006 were as follows (amount in thousands):

	March 31, 2007		**December 31, 2006**	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Term Loan(1)	$830,800	$832,877	$832,900	$834,462
Cal Dive Revolving Credit Facility(2)	172,000	172,000	201,000	201,000
Convertible Senior Notes(1)	300,000	418,908	300,000	378,780
MARAD Debt(3)	129,398	124,481	131,286	126,691
Loan Notes(4)	11,157	11,157	11,146	11,146

(1) The fair values of these instruments were based on quoted market prices as of March 31, 2007 and December 31, 2006, as applicable.

(2) The carrying value of the Cal Dive revolving credit facility approximates fair value as of March 31, 2007 and December 31, 2006.

(3) The fair value of the MARAD debt was

determined by a third-party evaluation of the remaining average life and outstanding principal balance of the MARAD indebtedness as compared to other government guaranteed obligations in the market place with similar terms.

(4) The carrying value of the loan notes approximates fair value as the maturity dates of these securities are less than one year.

Table of Contents

Note 10 Income Taxes

The effective tax rate of 33.8% for the three months ended March 31, 2007 was lower than the effective rate of 34.1% for the same period in 2006. The lower tax rate was primarily due to an increase in the benefit derived from the Internal Revenue Code section 199 manufacturing deduction as it primarily related to oil and gas production and contracting services in the Gulf of Mexico and the revaluation of deferred taxes as a result of the lower statutory tax rates in foreign jurisdictions. This benefit was partially offset by the requirement under Statement of Financial Accounting Standard No. 109, *Accounting for Income Taxes*, that taxes be provided on the un-remitted portion of earnings.

We adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48) on January 1, 2007. The impact of the adoption of FIN 48 was immaterial on our financial position, results of operations and cash flows. We record tax related interest in interest expense and tax penalties in operating expenses as allowed under FIN 48. As of March 31, 2007, we had no material unrecognized tax benefits and no material interest and penalties were recognized.

We file tax returns in the U.S. and in various state, local and non-U.S. jurisdictions. We anticipate that any potential adjustments to our state, local and non-U.S. jurisdiction tax returns by tax authorities would not have a material impact on our financial position. The tax periods ending December 31, 2002, 2003, 2004, 2005 and 2006 remain subject to examination by the U.S. Internal Revenue Service (IRS). In addition, as we acquired Remington on July 1, 2006, we are exposed to any tax uncertainties related to Remington. For Remington, the tax periods ending December 31, 2003, 2004, 2005, and June 30, 2006 remain subject to examination by the IRS. The 2004 and 2005 tax returns for Remington are currently under examination by the IRS. The 2004 tax return includes the utilization of a net operating loss generated prior to 1999. As of March 31, 2007, the IRS has not yet issued any proposed adjustments for the years under examination.

Note 11 Hedging Activities

We are currently exposed to market risk in three major areas: interest rates, commodity prices and foreign currency exchange rates. Our risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to our oil and gas production, variable interest rate exposure and foreign currency exposure. All derivatives are reflected in our balance sheet at fair value, unless otherwise noted.

Commodity Hedges

We have entered into various cash flow hedging costless collar contracts to stabilize cash flows relating to a portion of our expected oil and gas production. All of these qualified for hedge accounting. The aggregate fair value of the hedge instruments was a net (liability) asset of ($7.5 million) and $5.2 million as of March 31, 2007 and December 31, 2006, respectively. We recorded unrealized (losses) gains of approximately ($8.3 million) and $3.2 million, net of tax (benefit) expense of ($4.5 million) and $1.7 million, respectively, during the three months ended March 31, 2007 and 2006, respectively, in accumulated other comprehensive income, a component of shareholders equity, as these hedges were highly effective. During the three months ended March 31, 2007 and 2006, we reclassified approximately $2.1 million and $4.9 million of gains, respectively, from other comprehensive income to net revenues upon the sale of the related oil and gas production.

Table of Contents

As of March 31, 2007, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling 1,260 MBbl of oil and 13,700 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
April 2007 December 2007	Collar	100 MBbl	$ 50.00 $67.55
January 2008 June 2008	Collar	60 MBbl	$ 55.00 $73.58
Natural Gas:			
April 2007 June 2007	Collar	600,000 MMBtu	$ 7.83 $10.28
July 2007 December 2007	Collar	1,083,333 MMBtu	$ 7.50 $10.10
January 2008 June 2008	Collar	900,000 MMBtu	$ 7.25 $10.73

We have not entered into any hedge instruments subsequent to March 31, 2007. 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.

As of March 31, 2007, we had oil forward sales contracts for the period from April 2007 through June 2007. The contracts cover an average of 30 MBbl per month at a weighted average price of $71.10. In addition, we had natural gas forward sales contracts for the period from April 2007 through June 2007. The contracts cover an average of 606,666 MMbtu per month at a weighted average price of $9.72. Hedge accounting does not apply to these contracts as these contracts qualify as normal purchases and sales transactions.

Interest Rate Hedge

As the rates for our Term Loan are subject to market influences and will vary over the term of the loan, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payments for our Term Loan. The interest rate swaps were effective October 3, 2006. These interest rate swaps qualify for hedge accounting. See Note 9 Long-Term Debt above for a detailed discussion of our Term Loan. The aggregate fair value of the hedge instruments was a net liability of $1.2 million and $531,000 as of March 31, 2007 and December 31, 2006, respectively. For the three months ended March 31, 2007, these hedges were highly effective.

Foreign Currency Hedge

In December 2006, we entered into various foreign exchange forwards to stabilize expected cash outflows relating to a shipyard contract where the contractual payments are denominated in euros. These forward contracts qualify for hedge accounting. Under the forward contracts, we have hedged payments totaling 18.0 million to be settled in June and December 2007 at exchange rates of 1.3255 and 1.3326, respectively. The aggregate fair value of the hedge instruments was a net asset (liability) of $226,000 and ($184,000) as of March 31, 2007 and December 31, 2006, respectively. For the three months ended March 31, 2007, these hedges were highly effective.

Note 12 Comprehensive Income

The components of total comprehensive income for the three months ended March 31, 2007 and 2006 were as follows (in thousands):

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Net income	$ 56,765	$ 56,193
Foreign currency translation gain	637	1,160
Unrealized gain (loss) on hedges, net	(8,190)	3,230
Total comprehensive income	$ 49,212	$ 60,583

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

	March 31, 2007	December 31, 2006
Cumulative foreign currency translation adjustment	$ 25,217	$ 24,580
Unrealized gain (loss) on hedges, net	(5,534)	2,656
Accumulated other comprehensive income	$ 19,683	$ 27,236

Note 13 Earnings Per Share

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

	Three Months Ended March 31, 2007		Three Months Ended March 31, 2006	
	Income	Shares	Income	Shares
Earnings applicable per common share Basic	$ 55,820	89,994	$ 55,389	77,969
Effect of dilutive securities:				
Stock options		364		630
Restricted shares		132		115
Employee stock purchase plan		12		
Convertible Senior Notes		179		1,458
Convertible preferred stock	945	3,631	804	3,631
Earnings applicable per common share Diluted	$ 56,765	94,312	$ 56,193	83,803

There were no antidilutive stock options in the three months ended March 31, 2007 and 2006 as all the options were in the money. Net income for the diluted earnings per share calculation for the three months ended March 31, 2007 and 2006 was adjusted to add back the preferred stock dividends on the 3.6 million shares.

Note 14 Stock-Based Compensation Plans

We have three stock-based compensation plans: the 1995 Long-Term Incentive Plan, as amended (the 1995 Incentive Plan), the 2005 Long-Term Incentive Plan, as amended (the 2005 Incentive Plan) and the 1998 Employee

Stock Purchase Plan, as amended (the ESPP).

We began accounting for our stock-based compensation plans under the fair value method beginning January 1, 2006. We continue to use the Black-Scholes option pricing model for valuing stock options and recognize compensation cost for our share-based payments on a straight-line basis over the respective vesting period. During first quarter 2007, we granted 680,143 shares of restricted shares to certain key executives, selected management employees and non-employee members of the board of directors under the 2005 Incentive Plan. The average market value of the restricted shares was $31.48 per share, or $21.4 million at the date of grant. For 2007 restricted share grants to executives and selected management employees, we estimated that 8% may be forfeited as the number of restricted stock recipients has increased. No forfeitures were estimated for outstanding unvested options and restricted shares granted prior to January 1, 2007 as historical forfeitures have been immaterial. There were no stock option grants in the first quarter of 2007.

For the three months ended March 31, 2007 and 2006, $265,000 and $403,000, respectively, was recognized as compensation expense related to stock options. Future compensation cost associated with unvested options at March 31, 2007 was approximately $1.6 million. The weighted average vesting period related to unvested stock options at March 31, 2007 was approximately 1.4 years. For the three months ended March 31, 2007 and 2006, $3.0 million (of which $503,000 of expense is related to CDI s stock-based compensation plan) and $1.2 million, respectively, were recognized as compensation expense related to restricted shares. Future compensation cost associated with unvested restricted shares at March 31, 2007 was approximately $34.1 million. The weighted average vesting period related to unvested restricted shares at March 31, 2007 was approximately 4.0 years.

Employee Stock Purchase Plan

Effective May 12, 1998, we adopted a qualified, non-compensatory ESPP, which allows employees to acquire shares of common stock through payroll deductions over a six month period. The purchase price is equal to 85 percent 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 10 percent of an employee s base salary. In January 2007, we issued 109,754 shares of our common stock to our employees under this plan to satisfy the employee purchase period from July 1, 2006 to December 31, 2006, which increased our common stock outstanding. We subsequently repurchased the same number of shares of our common stock in the open market at $29.94 per share and reduced the number of shares of our common stock outstanding. During the three months ended March 31, 2006, 41,006 shares of common stock were purchased in the open market at a share price of $26.14. For the three months ended March 31, 2007, we recognized $500,000 of compensation expense related to stock purchased under the ESPP.

Note 15 Business Segment Information (in thousands)

Our operations are conducted through two lines of business: contracting services operations and oil and gas operations. We have disaggregated our contracting services operations into three reportable segments in accordance with SFAS 131: Contracting Services, Shelf Contracting and Production Facilities. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Oil and Gas and Production Facilities. Contracting Services segment include deepwater pipelay, well operations, robotics and reservoir and well tech services. Shelf Contracting segment consist of assets deployed primarily for diving-related activities and shallow water construction. See Note 4 for discussion of the initial public offering of CDI common stock (represented by the Shelf Contracting segment). All material intercompany transactions between the segments have been eliminated.

We evaluate our performance based on income before income taxes of each segment. Segment assets are comprised of all assets attributable to the reportable segment. The majority of our Production Facilities segment (Deepwater Gateway and Independence) 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.

Table of Contents

	Three Months Ended March 31, 2007	2006
Revenues		
Contracting Services	$ 137,717	$ 101,031
Shelf Contracting	149,226	119,790
Oil and Gas	130,967	80,312
Intercompany elimination	(21,855)	(9,485)
Total	$ 396,055	$ 291,648
Income from operations		
Contracting Services	$ 22,873	$ 20,621
Shelf Contracting[(1)]	49,249	46,802
Oil and Gas	39,445	16,966
Production Facilities[(2)]	(187)	(318)
Intercompany elimination	(5,413)	
Total	$ 105,967	$ 84,071
Equity in earnings of equity investments excluding OTSL	$ 5,152	$ 3,403

(1) Included $952,000 and $2.8 million equity in earnings from investment in OTSL during the three months ended March 31, 2007 and 2006, respectively.

(2) Represents selling and administrative expense of Production Facilities incurred by us. See equity in earnings of equity

investments
excluding OTSL
for earnings
contribution.

	March 31, 2007	December 31, 2006
Identifiable Assets		
Contracting Services	$ 1,069,536	$ 1,313,206
Shelf Contracting	465,994	452,153
Oil and Gas	2,366,649	2,282,715
Production Facilities	257,592	242,113
Total	$ 4,159,771	$ 4,290,187

Intercompany segment revenues during the three months ended March 31, 2007 and 2006 were as follows:

	Three Months Ended March 31,	
	2007	2006
Contracting Services	$ 14,596	$ 7,155
Shelf Contracting	7,259	2,330
Total	$ 21,855	$ 9,485

Intercompany segment profit (which related primarily to intercompany capital projects) during the three months ended March 31, 2007 and 2006 was as follows:

	Three Months Ended March 31,	
	2007	2006
Contracting Services	$ 2,018	$
Shelf Contracting	3,395	
Total	$ 5,413	$

17

During the three months ended March 31, 2007 and 2006, we derived $40.6 million and $29.1 million, respectively, of our revenues from our operations in the United Kingdom, utilizing $242.9 million and $168.4 million, respectively, of our total assets in this region. The majority of the remaining revenues were generated in the U.S. Gulf of Mexico.

Note 16 Related Party Transactions

In April 2000, we acquired a 20% working interest in *Gunnison, a* Deepwater Gulf of Mexico prospect of Kerr-McGee Oil & Gas Corp. Financing for the exploratory costs of approximately $20 million was provided by an investment partnership (OKCD Investments, Ltd. or OKCD) in exchange for a revenue interest that is an overriding royalty interest of 25% of our 20% working interest. The investors of this entity include certain current and former members of Helix senior management. Production began in December 2003. Payments to OKCD from us totaled $6.0 million and $9.6 million in the three months ended March 31, 2007 and 2006, respectively.

Note 17 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 be approximately $110 million, of which approximately $26.2 million had been incurred, with an additional $55.0 million committed at March 31, 2007. In addition, we will upgrade the *Q4000* to include drilling via the addition of a modular-based drilling system for approximately $43 million, of which approximately $18.9 million had been incurred, with an additional $17.2 million committed, at March 31, 2007.

We also have committed to the construction of a $160 million multi-service dynamically positioned dive support/ well intervention vessel (*Well Enhancer*) that will be capable of working in the North Sea and West of Shetlands to support our expected growth in that region. We expect the *Well Enhancer* to join our fleet in 2008. At March 31, 2007, we had incurred approximately $22.4 million, with an additional $85.0 million committed to this project.

Further, we, along with Kommandor RØMØ, a Danish corporation, formed Kommandor LLC to begin the conversion of a ferry vessel into a dynamically-positioned construction vessel. The cost of the ferry and the conversion is approximately $85 million. Kommandor RØMØ and we are each responsible for 50% of the vessel and conversion cost. Upon completion of the conversion scheduled for the end of 2007, we will charter the vessel from Kommandor LLC, and will install at 100% our cost processing facilities and a disconnectable fluid transfer system (DTS) on the vessel for use on our *Phoenix* field. The cost of these facilities is approximately $100 million. 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 March 31, 2007 in our Production Facilities segment. Kommandor LLC has been a development stage enterprise since its formation in October 2006.

In addition, as of March 31, 2007, we have also committed approximately $110.0 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, we from time to time incur other claims, such as contract disputes, in the normal course of business.

Table of Contents

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 Deepwater Water Royalty Relief Act of 2005 (DWRRA), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases. 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 Deep Water Gulf of Mexico who have received notices similar to ours are seeking royalty relief under the DWRRA, including Kerr-McGee Oil and Gas Corporation (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, such as ours. We do not anticipate that the MMS director will issue decisions in ours or the other companies administrative appeals until the Kerr-McGee litigation has been resolved. As a result of this dispute, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed) plus interest at 5% for our portion of the *Gunnison* related MMS claim. The total reserved amount at March 31, 2007 and December 31, 2006 was approximately $45.4 million and $42.6 million, respectively. At this time, it is not anticipated that any penalties would be assessed even if we are unsuccessful in our appeal.

Although the above discussed matters may have the potential for additional liability and may have an impact on our consolidated financial results for a particular reporting period, we believe that the outcome of all such matters and proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Note 18 Recently Issued Accounting Principles

In September 2006, the FASB issued Statement of Financial Accounting Standard No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of adopting this statement.

In February 2007, the FASB issued Statement of Financial Accounting Standard No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS No. 159). SFAS No. 159 allows entities to voluntarily choose, at specified election dates, to measure many financial assets and financial liabilities at fair value. The election is made on an instrument-by-instrument basis and is irrevocable. If the fair value option is elected for an instrument, SFAS No. 159 specifies that all subsequent changes in fair value for that instrument shall be reported in earnings. The provisions of SFAS No. 159 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of adopting this statement.

Table of Contents

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. 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 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 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; and
- statements regarding any financing transactions or arrangements, or ability to enter into such transactions;
- statements relating to the construction or acquisition of vessels or equipment and our proposed acquisition of any producing property or well prospect, 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 or other financial items;
- statements regarding our business strategy, our business plans or any other plans, forecasts or objectives, any or all of which are subject to change;
- statements regarding any Securities and Exchange Commission 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 relating to our services or any statements related to the underlying assumptions related to any projection or forward-looking statement;
- statements related to environmental risks, drilling and operating risks, or exploration and development risks and the ability of the combined company to retain key members of its senior management and key employees;
- statements regarding general economic or political conditions, whether internationally, nationally or in the regional and local market areas in which we are doing business;
- 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, ir 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 Annual Report on Form 10-K for the year ended December 31, 2006. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these risk factors. Forward-looking statements are only as of the date they are made, and other than as required under the securities laws, we assume no obligation to update or revise these forward-looking statements or provide reasons why actual results may differ.

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. There have been no material changes or developments in authoritative accounting pronouncements or in our evaluation of the accounting estimates and the underlying assumptions or methodologies that we believe would change the Critical Accounting Policies and Estimates as disclosed in our Form 10-K for the year ended December 31, 2006.

Recently Issued Accounting Principles

In September 2006, the FASB issued SFAS No. 157. This statement defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of this statement.

In February 2007, the FASB issued SFAS No. 159, which allows entities to voluntarily choose, at specified election dates, to measure many financial assets and financial liabilities at fair value. The election is made on an instrument-by-instrument basis and is irrevocable. If the fair value option is elected for an instrument, SFAS No. 159 specifies that all subsequent changes in fair value for that instrument shall be reported in earnings. The provisions of SFAS No. 159 are effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, of this statement.

RESULTS OF OPERATIONS

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 131. As a result, our reportable segments consist of the following: Contracting Services, Shelf Contracting, Oil and Gas and Production Facilities. Contracting Services segment include services such as deepwater pipelay, well operations, robotics and reservoir and well tech services. Shelf Contracting segment consist of assets deployed primarily for diving-related activities and shallow water construction. See Note 4 Initial Public Offering of Cal Dive International, Inc. for discussion of the initial public offering of CDI common stock (represented by the Shelf Contracting segment). All material intercompany transactions between the segments have been eliminated in our consolidated results of operations.

Table of Contents

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006	Increase/ (Decrease)
Revenues (in thousands)			
Contracting Services	$ 137,717	$ 101,031	$ 36,686
Shelf Contracting	149,226	119,790	29,436
Oil and Gas	130,967	80,312	50,655
Intercompany elimination	(21,855)	(9,485)	(12,370)
	$ 396,055	$ 291,648	$ 104,407
Gross profit (in thousands)			
Contracting Services	$ 34,494	$ 29,438	$ 5,056
Shelf Contracting	57,952	50,206	7,746
Oil and Gas	48,582	22,622	25,960
Intercompany elimination	(5,413)		(5,413)
	$ 135,615	$ 102,266	$ 33,349
Gross Margin			
Contracting Services	25%	29%	(4) pts
Shelf Contracting	39%	42%	(3) pts
Oil and Gas	37%	28%	9 pts
Total company	34%	35%	(1) pt
Number of vessels(1)/ Utilization(2)			
Contracting Services:			
Pipelay	3/93%	3/100%	
Well operations	2/65%	2/71%	
ROVs	33/70%	33/70%	
Shelf Contracting	25/70%	23/89%	

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

vessels jointly owned with a third party.

(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 March 31, 2007 and 2006 were as follows (in thousands):

	Three Months Ended March 31, 2007	2006	Increase/ (Decrease)
Contracting Services	$ 14,596	$ 7,155	$ 7,441
Shelf Contracting	7,259	2,330	4,929
	$ 21,855	$ 9,485	$ 12,370

Table of Contents

Intercompany segment profit (which related primarily to intercompany capital projects) during the three months ended March 31, 2007 and 2006 was as follows (in thousands):

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006	Increase/ (Decrease)
Contracting Services	$ 2,018	$	$ 2,018
Shelf Contracting	3,395		3,395
	$ 5,413	$	$ 5,413

The following table details various financial and operational highlights related to our Oil and Gas segment (U.S. operations only) for the periods presented:

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006	Increase/ (Decrease)
Oil and Gas information			
Oil production volume (MBbls)	959	555	404
Oil sales revenue (in thousands)	$ 54,053	$ 32,558	$ 21,495
Average oil sales price per Bbl (excluding hedges)	$ 56.11	$ 58.71	$ (2.60)
Average realized oil price per Bbl (including hedges)	$ 56.36	$ 58.71	$ (2.35)
Increase (decrease) in oil sales revenue due to:			
Change in prices (in thousands)	$ (1,306)		
Change in production volume (in thousands)	22,801		
Total increase in oil sales revenue (in thousands)	$ 21,495		
Gas production volume (MMcf)	9,847	4,954	4,893
Gas sales revenue (in thousands)	$ 75,431	$ 46,732	$ 28,699
Average gas sales price per mcf (excluding hedges)	$ 7.47	$ 8.45	$ (0.98)
Average realized gas price per mcf (including hedges)	$ 7.66	$ 9.43	$ (1.77)
Increase (decrease) in gas sales revenue due to:			
Change in prices (in thousands)	$ (8,780)		
Change in production volume (in thousands)	37,479		
Total increase in gas sales revenue (in thousands)	$ 28,699		
Total production (MMcfe)	15,601	8,282	7,319
Price per Mcfe	$ 8.30	$ 9.57	$ (1.27)

Presenting the expenses of our Oil and Gas segment (U.S. operations only) 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) and on this basis with barrels of oil converted to Mcfe at a ratio of one barrel to six Mcf:

	Three Months Ended March 31,			
	2007		2006	
	Total	Per Mcfe	Total	Per Mcfe
Oil and gas operating expenses(1):				
Direct operating expenses(2)	$ 21,998	$ 1.41	$ 11,846	$ 1.43
Repairs and maintenance	6,547	0.42	3,704	0.45
Other	1,324	0.08		
Total	$ 29,869	$ 1.91	$ 15,550	$ 1.88
Depletion expense	$ 46,918	$ 3.01	$ 18,183	$ 2.19
Accretion expense	$ 2,522	$ 0.16	$ 1,852	$ 0.22

(1) Excludes exploration expense of $1.2 million and $22.1 million for the three months ended March 31, 2007 and 2006, respectively. Exploration expense is not a component of lease operating expense.

(2) Includes production taxes.

Results of operations for our Oil and Gas segment in the United Kingdom were immaterial for the three months ended March 31, 2007 and 2006.

Comparison of Three Months Ended March 31, 2007 and 2006

Revenues. During the three months ended March 31, 2007, our revenues increased by 36% as compared to the same period in 2006. Contracting Services revenues increased primarily due to improved market demand (resulting in improved contract pricing for the pipelay, well operations and ROV divisions). These increases were partially offset by lower utilization in the first quarter of 2007 as a result of downtime for our well operations vessels due to a planned drydock for one of our vessels and unplanned downtime for the other vessel. Shelf Contracting revenues increased primarily as a result of the Torch, Acergy and Fraser acquisitions in the third and fourth quarters of 2005 and third quarter of 2006, respectively. These increases were partially offset by lower utilization for the utility vessels in our

Shelf Contracting segment.

Oil and Gas revenues increased 63% during the three months ended March 31, 2007 as compared to the same period in 2006. The increase was primarily due to increases in oil and natural gas production. The production volume increase of 88% over the three months ended March 31, 2006 was mainly attributable to the Remington acquisition. The Oil and Gas revenues increase was partially offset by lower oil and gas prices realized in the first quarter of 2007 as compared to the same prior year period.

Gross Profit. Gross profit in the first quarter of 2007 increased 33% as compared to the same period in 2006. The Contracting Services gross profit increase was primarily attributable to improved contract pricing for the pipelay, well operations and ROV divisions. The gross margin decrease for Contracting Services was primarily due to our fulfillment of our lower margin work bid in 2005 for our pipelay assets, and lower utilization of our well operations vessels as discussed above. The gross profit increase within Shelf Contracting was primarily attributable to additional gross profit derived from the Torch, Acergy and Fraser acquisitions. The gross margin decrease in first quarter 2007 as compared to the same prior year period for Shelf Contracting was due to overall lower margins in the international markets and increased depreciation and amortization related to deferred drydock costs on newly deployed vessels and other vessel upgrades.

Table of Contents

The Oil and Gas gross profit increase in first quarter 2007 as compared to the same period in 2006 was primarily due to higher oil and gas production as discussed above. In addition, gross profit and gross margin were higher in the first quarter of 2007 as compared to 2006 as a result of decreased exploration costs of approximately $20.9 million in the three months ended March 31, 2007 as compared to the same period in 2006. Exploration costs were higher in first quarter 2006 as a result of the $20.7 million dry hole expense related to the Tulane prospect. The gross profit increase was partially offset by lower oil and gas prices as discussed above.

Selling and Administrative Expenses. Selling and administrative expenses of $30.6 million for the first quarter of 2007 were $9.6 million higher than the $21.0 million incurred in the same prior year period. The increase was due primarily to higher overhead to support our growth. Selling and administrative expenses increased slightly to 8% of revenues in the three months ended March 31, 2007 as compared to 7% in the same prior year period.

Equity in Earnings of Investments. Equity in earnings of our 50% investment in Deepwater Gateway increased to $4.7 million in the three months ended March 31, 2007 compared with $3.4 million in the same prior year period. The increase was due to higher throughput at the *Marco Polo* TLP. Further, equity in earnings of our 20% investment in Independence Hub increased $495,000 as we reached substantial mechanical completion in March 2007 and began receiving demand fees. These increases were offset by a $1.9 million decrease in equity in earnings in our 40% minority ownership interest in OTSL during the first quarter of 2007 as compared to 2006.

Net Interest Expense and Other. We reported net interest and other expense of $13.0 million in the first quarter of 2007 as compared to $2.2 million in the prior year. Gross interest expense of $23.1 million during the three months ended March 31, 2007 was higher than the $4.5 million incurred in 2006 as a result of our Term Loan, which closed in July 2006, and CDI s revolving credit facility, which closed in December 2006. Offsetting the increase in interest expense was $5.4 million of capitalized interest and $4.6 million of interest income in the first quarter of 2007, compared with $1.2 million of capitalized interest and $819,000 of interest income in the same prior year period.

Provision for Income Taxes. Income taxes increased to $33.1 million in the three months ended March 31, 2007 compared to $29.1 million in the same prior year period primarily due to increased profitability. This increase was partially offset by a lower effective tax rate for the first quarter of 2007 of 33.8% compared with 34.1% for same prior year period.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

	March 31, 2007	December 31, 2006
Net working capital	$ 213,988	$ 310,524
Long-term debt[1]	1,420,764	1,454,469

(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.

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Net cash provided by (used in):		
Operating activities	$(63,054)	$ 87,530
Investing activities	$ 77,795	$(151,633)
Financing activities	$(37,984)	$ 10,716

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 Credit Facilities, Convertible Senior Notes, MARAD Debt and Cal Dive s credit facility, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of March 31, 2007 and December 31, 2006, we were in compliance with these covenants. The Senior Credit Facilities contain provisions that limit our ability to incur certain types of additional indebtedness. These provisions effectively prohibit us from incurring any additional secured indebtedness or indebtedness guaranteed by the Company. The Senior Credit Facilities do, however, permit us to incur unsecured indebtedness, and also permit our subsidiaries to incur project financing indebtedness (such as our MARAD Debt) secured by the underlying asset, provided that the indebtedness is not guaranteed by us.

For the remainder of 2007, assuming the current balance of the CDI revolver remains outstanding, we expect to make $67.5 million of interest payments, excluding the effect of interest rate swaps. In addition, we expect to make preferred dividend payments totaling approximately $2.8 million for the remainder of 2007. As of March 31, 2007, we had $300 million of available borrowing capacity under our credit facilities, and CDI had $78 million of available borrowing under its revolving credit facility. See Note 9 Long-term Debt for additional information related to our long-term obligations, including our obligations under capital commitments.

Working Capital

Cash flow from operating activities decreased $150.6 million in the three months ended March 31, 2007 as compared to the same period in 2006. This decrease was primarily due to income taxes paid in first quarter 2007 of approximately $154.4 million, most of which ($126.6 million) was related to the proceeds received from the CDI initial public offering.

Table of Contents

Investing Activities

Capital expenditures have consisted principally of strategic asset acquisitions related to the purchase or construction of DP vessels, acquisition of select businesses, improvements to existing vessels, acquisition of oil and gas properties and investments in our production facilities. Significant sources (uses) of cash associated with investing activities for the three months ended March 31, 2007 and 2006 were as follows (in thousands):

	Three Months Ended March 31,	
	2007	**2006**
Capital expenditures:		
Contracting Services	$ (39,514)	$ (31,568)
Shelf Contracting	(2,146)	(4,990)
Oil and Gas[1]	(126,731)	(24,565)
Production Facilities	(13,508)	(338)
Acquisition of businesses, net of cash acquired:		
Remington Oil and Gas Corporation[2]	(79)	
Acergy US. Inc.		(77,927)
Sale of short-term investments	265,820	
Investments in production facilities	(10,294)	(11,373)
Distributions from equity investments, net[3]	4,896	635
Increase in restricted cash	(266)	(3,038)
Proceeds from sale of properties	(383)	1,531
Cash provided by (used in) investing activities	$ 77,795	$ (151,633)

(1) Includes approximately $126,000 and $20.7 million of capital expenditures related to exploratory dry holes in the three months ended March 31, 2007 and 2006. For additional information, see Note 6.

(2) For additional information related to the Remington acquisition, see Note 5.

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

Short-term Investments

As of March 31, 2007 and December 31, 2006, we held approximately $19.6 million and $285.4 million, respectively, in municipal auction rate securities. These instruments are long-term variable rate bonds tied to short-term interest rates that are reset through a Dutch Auction process which occurs every 7 to 35 days and have been classified as available-for-sale securities. Although these instruments do not meet the definition of cash and cash equivalents, we expect to use these instruments to fund our working capital as needed due to the liquid nature of these securities.

Restricted Cash

As of March 31, 2007 and December 31, 2006, we had $33.9 million and $33.7 million of restricted cash, respectively, included in other assets, net, in the accompanying condensed consolidated balance sheet, all of which related to the escrow funds for decommissioning liabilities associated with the SMI 130 acquisition in 2002 by our Oil and Gas segment. We have fully satisfied the escrow requirement as of March 31, 2007. We may use the restricted cash for decommissioning the related field.

Table of Contents

Equity Investments

We made the following contributions to our equity investments during the three months ended March 31, 2007 and 2006 (in thousands):

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Independence	$ 7,935	$ 11,373
Other	2,359	
Total	$ 10,294	$ 11,373

We received the following distributions from our equity investments during the three months ended March 31, 2007 and 2006 (in thousands):

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
Deepwater Gateway	$ 11,000	$ 4,000
OTSL		68
Total	$ 11,000	$ 4,068

Oil and Gas Exploration Activities

In February 2007, we completed the drilling of an exploratory well in our 100% owned Noonan prospect located in the Gulf of Mexico. Development plans being screened include a fast track subsea tie-back to selected infrastructure located in shallower water. First production should be achieved in the second half of 2008. As of March 31, 2007, approximately $59.9 million of exploratory capitalized project costs was related to Noonan.

Outlook

We anticipate capital expenditures for the remainder of 2007 will range from $650 million to $950 million. We may increase or decrease these plans based on various economic factors. We believe internally generated cash flow, the cash generated from the Cal Dive initial public offering and borrowings under our existing credit facilities will provide the necessary capital to fund our 2007 initiatives.

Table of Contents

The following table summarizes our contractual cash obligations as of March 31, 2007 and the scheduled years in which the obligations are contractually due (in thousands):

	Total [(1)]	Less Than 1 year	1-3 Years	3-5 Years	More Than 5 Years
Convertible Senior Notes[(2)]	$ 300,000	$	$	$	$ 300,000
Term Loan	830,800	8,400	16,800	16,800	788,800
MARAD debt	129,398	3,917	8,431	9,293	107,757
CDI Revolving Credit Facility	172,000			172,000	
Loan notes	11,157	11,157			
Capital leases	3,402	2,519	883		
Drilling and development costs	110,000	110,000			
Property and equipment[(3)]	174,348	174,348			
Operating leases[(4)]	59,317	32,403	17,849	4,900	4,165
Other[(5)]	5,790	4,100	1,690		
Total cash obligations	$ 1,796,212	$ 346,844	$ 45,653	$ 202,993	$ 1,200,722

(1) Excludes unsecured letters of credit outstanding at March 31, 2007 totaling $36.5 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Maturity 2025. Can be converted prior to stated maturity (see Note 9). To the extent we do not have alternative long-term financing secured to cover

the conversion, the Convertible Senior Notes would be classified as a current liability in the accompanying balance sheet. As of March 31, 2007, no conversion triggers were met.

(3) Costs incurred as of March 31, 2007 and additional property and equipment commitments at March 31, 2007 consisted of the following (in thousands):

	Costs Incurred	Costs Committed	Total Project Cost
Caesar conversion	$ 26,243	$ 54,952	$ 110,000
Q4000 upgrade	18,897	17,218	43,000
Well Enhancer construction	22,426	84,967	160,000
Helix Producer I conversion[a]	23,244	17,211	165,000
Total	$ 90,810	$ 174,348	$ 478,000

(a) Represents 100% of the vessel conversion cost, of which we expect our portion to be approximately $132.5 million.

(4) Operating leases included facility leases and

vessel charter leases. Vessel charter lease commitments at March 31, 2007 were approximately $39.6 million.

(5) Other consisted of scheduled payments pursuant to 3-D seismic license agreements.

Contingencies

In orders from the MMS dated December 2005 and May 2006, ERT received notice from the MMS that the 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 March 31, 2007, we have approximately $45.4 million accrued for the related royalties and interest. See Note 17 for a detailed discussion of this contingency.

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 March 31, 2007, not considering the effects of interest rate swaps, approximately 70.1% of our outstanding debt was based on floating rates. As a result, we are subject to interest rate risk. In September 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. Excluding the portion of our 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 $2.6 million in interest expense for the three months ended March 31, 2007. Interest rate risk was immaterial in the three months ended March 31, 2006 as none of our outstanding debt at such date was based on floating rates.

Commodity Price Risk. As of March 31, 2007, we had the following volumes under derivative contracts related to our oil and gas producing activities totaling 1,260 MBbl of oil and 13,700 MMbtu of natural gas:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
April 2007 December 2007	Collar	100 MBbl	$50.00 $67.55
January 2008 June 2008	Collar	60 MBbl	$55.00 $73.58
Natural Gas:			
April 2007 June 2007	Collar	600,000 MMBtu	$ 7.83 $10.28
July 2007 December 2007	Collar	1,083,333 MMBtu	$ 7.50 $10.10
January 2008 June 2008	Collar	900,000 MMBtu	$ 7.25 $10.73

We have not entered into any hedge instruments subsequent to March 31, 2007. 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.

As of March 31, 2007, we had oil forward sales contracts for the period from April 2007 through June 2007. The contracts cover an average of 30 MBbl per month at a weighted average price of $71.10. In addition, we had natural gas forward sales contracts for the period from April 2007 through June 2007. The contracts cover an average of 606,666 MMbtu per month at a weighted average price of $9.72. Hedge accounting does not apply to these contracts as these contracts qualify as normal purchases and sales transactions.

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. In December 2006, we entered into various foreign exchange forwards to stabilize expected cash outflows relating to a shipyard contract where the contractual payments are denominated in euros. These forward contracts qualify for hedge accounting. We have hedged payments totaling 18.0 million to be settled in June and December 2007 at exchange rates of 1.3255 and 1.3326, respectively. The aggregate fair value of the hedge instruments was a net asset (liability) of $226,000 and ($184,000) as of March 31, 2007 and December 31, 2006, respectively. For the three months ended March 31, 2007, we recorded unrealized gains of approximately $331,000, net of tax expense of $79,000, in accumulated other comprehensive income, a component of shareholders equity, as these hedges were highly effective.

Item 4. Controls and Procedures

(a) *Evaluation of disclosure controls and procedures*. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the fiscal quarter ended March 31, 2007. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended March 31, 2007 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

Table of Contents

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 Securities Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 17 to the Condensed Consolidated Financial Statements, which is incorporated herein by reference.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum value of shares that may yet be purchased under the program
January 1 to January 31, 2007[1]	118,495	$ 29.83		$ N/A
February 1 to February 28, 2007[2]	12,170	32.17		N/A
March 1 to March 31, 2007[2]	841	34.84		N/A
	131,506	$ 30.08		$ N/A

(1) Includes 109,754 shares of our common stock to our employees under our 1998 Employee Stock Purchase Plan to satisfy the employee purchase period from July 1, 2006 to December 31, 2006. We subsequently repurchased the same number of shares of our common stock in the open market at $29.94 per

share. Also includes shares subject to restricted share awards withheld to satisfy tax obligations arising upon the vesting of restricted shares.

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

Item 6. Exhibits

15.1	Independent Registered Public Accounting Firm s Acknowledgement Letter(1)
31.1	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by Owen Kratz, Executive Chairman(1)
31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer(1)
32.1	Section 1350 Certification of Principal Executive Officer, Owen Kratz, Executive Chairman(2)
32.2	Section 1350 Certification of Principal Financial Officer, A. Wade Pursell, Chief Financial Officer(2)
99.1	Report of Independent Registered Public Accounting Firm(1)

(1) Filed herewith

(2) Furnished herewith

Table of Contents

SIGNATURES

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

HELIX ENERGY SOLUTIONS GROUP, INC.
(Registrant)

Date: May 4, 2007	By: **/s/ Owen Kratz** Owen Kratz Executive Chairman
Date: May 4, 2007	By: **/s/ A. Wade Pursell** A. Wade Pursell Executive Vice President and Chief Financial Officer

33

INDEX TO EXHIBITS
OF
HELIX ENERGY SOLUTIONS GROUP, INC.

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31.2	Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial Officer[(1)]
32.1	Section 1350 Certification of Principal Executive Officer, Owen Kratz, Executive Chairman[(2)]
32.2	Section 1350 Certification of Principal Financial Officer, A. Wade Pursell, Chief Financial Officer[(2)]
99.1	Report of Independent Registered Public Accounting Firm[(1)]

(1) Filed herewith

(2) Furnished herewith