HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
August 03, 2006

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

þ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended June 30, 2006

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 August 1, 2006, 91,519,121 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

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

	June 30, 2006 (Unaudited)	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 38,278	$ 91,080
Accounts receivable		
Trade, net of allowance for uncollectible accounts of $1,291 and $585	252,561	197,046
Unbilled revenue	31,717	31,012
Other current assets	58,105	52,915
Total current assets	380,661	372,053
Property and equipment	1,490,276	1,259,014
Less Accumulated depreciation	(395,973)	(342,652)
	1,094,303	916,362
Other assets:		
Equity investments	203,198	179,844
Goodwill, net	105,012	101,731
Other assets, net	97,413	90,874
	$ 1,880,587	$ 1,660,864
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 138,006	$ 99,445
Accrued liabilities	135,633	145,752
Current maturities of long-term debt	6,316	6,468
Total current liabilities	279,955	251,665
Long-term debt	437,970	440,703
Deferred income taxes	203,419	167,295
Decommissioning liabilities	110,757	106,317
Other long-term liabilities	8,984	10,584
Total liabilities	1,041,085	976,564
Convertible preferred stock	55,000	55,000

Commitments and contingencies		
Shareholders equity:		
Common stock, no par, 240,000 shares authorized, 105,695 and 104,898 shares issued	245,483	233,537
Retained earnings	533,276	408,748
Treasury stock, 27,211 and 27,204 shares, at cost	(3,977)	(3,741)
Unearned compensation		(7,515)
Accumulated other comprehensive income (loss)	9,720	(1,729)
Total shareholders equity	784,502	629,300
	$ 1,880,587	$ 1,660,864

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

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

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005
Net revenues	$ 305,013	$ 166,531
Cost of sales	173,321	114,112
Gross profit	131,692	52,419
Gain on sale of assets	16	
Selling and administrative expenses	27,414	12,858
Income from operations	104,294	39,561
Equity in earnings of investments	4,520	2,708
Net interest expense and other	2,983	913
Income before income taxes	105,831	41,356
Provision for income taxes	35,887	14,779
Net income	69,944	26,577
Preferred stock dividends	805	550
Net income applicable to common shareholders	$ 69,139	$ 26,027
Earnings per common share:		
Basic	$ 0.88	$ 0.34
Diluted	$ 0.83	$ 0.32
Weighted average common shares outstanding:		
Basic	78,462	77,444
Diluted	83,965	81,963

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

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

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Net revenues	$ 596,661	$ 326,106
Cost of sales	362,703	221,814
Gross profit	233,958	104,292
Gain on sale of assets	283	925
Selling and administrative expenses	48,442	25,696
Income from operations	185,799	79,521
Equity in earnings of investments	10,756	4,437
Net interest expense and other	5,440	2,102
Income before income taxes	191,115	81,856
Provision for income taxes	64,978	29,319
Net income	126,137	52,537
Preferred stock dividends	1,609	1,100
Net income applicable to common shareholders	$ 124,528	$ 51,437
Earnings per common share:		
Basic	$ 1.59	$ 0.67
Diluted	$ 1.51	$ 0.64
Weighted average common shares outstanding:		
Basic	78,216	77,294
Diluted	83,659	81,850

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

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

	Six Months Ended June 30,	
	2006	**2005**
Cash flows from operating activities:		
Net income	$ 126,137	$ 52,537
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	67,664	55,179
Asset impairment charge	20,654	790
Equity in earnings of investments, net of distributions	(2,938)	
Amortization of deferred financing costs	969	550
Stock compensation expense	3,816	397
Deferred income taxes	29,120	26,813
Gain on sale of assets	(283)	(925)
Excess tax benefit from stock-based compensation	(7,529)	
Changes in operating assets and liabilities:		
Accounts receivable, net	(51,312)	(10,847)
Other current assets	(1,754)	1,226
Accounts payable and accrued liabilities	(26,215)	17,311
Other noncurrent, net	(9,004)	(27,537)
Net cash provided by operating activities	149,325	115,494
Cash flows from investing activities:		
Capital expenditures	(125,794)	(214,345)
Acquisition of businesses, net of cash acquired	(78,174)	
Investments in production facilities	(19,019)	(95,564)
Distributions from equity investments, net		9,163
(Increase) decrease in restricted cash	(5,577)	441
Proceeds from sales of property	16,782	2,150
Net cash used in investing activities	(211,782)	(298,155)
Cash flows from financing activities:		
Borrowings on Convertible Senior Notes		300,000
Repayment of MARAD borrowings	(1,798)	(2,144)
Deferred financing costs	(1,914)	(8,013)
Capital lease payments	(1,491)	(1,394)
Preferred stock dividends paid	(1,863)	(1,100)
Redemption of stock in subsidiary		(2,438)
Repurchase of common stock	(225)	
Excess tax benefit from stock-based compensation	7,529	
Exercise of stock options, net	8,520	6,863

Net cash provided by financing activities	8,758	291,774
Effect of exchange rate changes on cash and cash equivalents	897	(566)
Net (decrease) increase in cash and cash equivalents	(52,802)	108,547
Cash and cash equivalents:		
Balance, beginning of year	91,080	91,142
Balance, end of period	$ 38,278	$ 199,689

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

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. (formerly known as Cal Dive International, Inc.) and its majority-owned subsidiaries (collectively, Helix or the Company). Unless the context indicates otherwise, the terms we, us and our in this report refer collectively to Helix and its subsidiaries. We account for our 50% interest in Deepwater Gateway, L.L.C., our 20% interest in Independence Hub, LLC (Independence) and our 40% interest in Offshore Technology Solutions Limited (OTSL) using the equity method of accounting as we do not have voting or operational control of these entities. 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, 2005. 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. The actual results may differ from our estimates. Please see our 2005 Annual Report on Form 10-K for a detailed description of our critical accounting policies. The SEC has defined critical accounting policies as the ones that are most important to the portrayal of a company s financial condition and results of operations and require the company to make its most difficult and subjective judgments, often as a result of the need to make estimates of matters that are inherently uncertain.

Management has reflected all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes are necessary for a fair presentation of the condensed consolidated balance sheets, results of operations and cash flows, as applicable. Operating results for the period ended June 30, 2006 are not necessarily indicative of the results that may be expected for the year ending December 31, 2006. Our balance sheet as of December 31, 2005 included herein has been derived from the audited balance sheet as of December 31, 2005 included in our 2005 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 2005 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. Reclassifications related primarily to reportable segment realignment in the fourth quarter of 2005.

Note 2 Statement of Cash Flow Information

We define cash and cash equivalents as cash and all highly liquid financial instruments with original maturities of less than three months. As of June 30, 2006 and December 31, 2005, we had $32.6 million and $27.0 million, respectively, of restricted cash included in other assets, net, all of which related to Energy Resource Technology, Inc. (ERT), a wholly owned subsidiary of the Company, escrow funds for decommissioning liabilities associated with the South Marsh Island 130 (SMI 130) field acquisitions in 2002. Under the purchase agreement for those acquisitions, ERT is obligated to escrow 50% of production up to the first $20 million of escrow and 37.5% of production on the remaining balance up to $33 million in total escrow. ERT may use the restricted cash for decommissioning the related fields.

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During the three and six months ended June 30, 2006, we made cash payments for interest charges, net of capitalized interest, of $3.6 million and $5.0 million, respectively, and $1.7 million and $3.4 million during the three and six months ended June 30, 2005, respectively. In addition, during the three and six months ended June 30, 2006, we paid $32.6 million and $41.4 million in income taxes, respectively. During the three and six months ended June 30, 2005, we paid $271,000 and $1.2 million in income taxes, respectively.

Non-cash investing activities for the six months ended June 30, 2006 included $62.6 million related to accruals of capital expenditures. The accruals have been reflected in the condensed consolidated balance sheet as an increase in property and equipment and accounts payable.

Note 3 Offshore 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. During the three months ended June 30, 2006, we did not recognize any impairment expense. For the six months ended June 30, 2006, impairments and unsuccessful capitalized well work totaling $20.7 million were expensed as a result of analyses on certain properties (see Tulane discussion below). During the three and six months ended June 30, 2005, impairments and unsuccessful capitalized well work totaling approximately $2.8 million and $4.4 million, respectively, were expensed as a result of analyses on certain properties. Furthermore, we expensed approximately $70,000 and $4.5 million of purchased seismic data related to our offshore properties in the six months ended June 30, 2006 and 2005, respectively. In addition, in the three and six months ended June 30, 2006, we expensed inspection and repair costs totaling approximately $5.5 million and $8.9 million, respectively, related to Hurricanes *Katrina* and *Rita*, partially offset by $2.7 million of insurance recoveries recognized in the first quarter of 2006.

As an extension of ERT s well exploitation and PUD strategies, ERT 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. The total estimated cost to us of approximately $20.7 million was charged to earnings in the first quarter of 2006. We continue to evaluate various options with the operator for recovering the potential reserves. Approximately $5.5 million of the equipment was redeployed and remains capitalized.

In March 2005, ERT acquired a 30% working interest in a proven undeveloped field in Atwater Block 63 (Telemark) of the Deepwater Gulf of Mexico for cash and assumption of certain decommissioning liabilities. In December 2005, ERT was advised by Norsk Hydro USA Oil and Gas, Inc. (Norsk Hydro) that Norsk Hydro will not pursue their development plan for the deepwater discovery. As a result, ERT acquired a 100% working interest and operatorship in April 2006 following a non-consent to the ERT plan of development by Norsk Hydro. ERT s interest in this property and surrounding fields were sold in July 2006 for $15 million in cash and with ERT also retaining a reservation of an overriding royalty interest in the Telemark development.

In April 2005, ERT entered into a participation agreement to acquire a 50% working interest in the Devil s Island discovery (Garden Banks Block 344 E/2) in 2,300 feet water depth. This deepwater development is operated by Hess. An appraisal well was drilled in April 2006 and was suspended. A new sidetrack well completion plan is currently under review. Participation in the additional sidetrack will require an amended participation agreement which is currently under negotiation with Hess. The field will ultimately be developed via a subsea tieback to Baldpate Field (Garden Banks Block 260). Our Contracting Services assets would participate in this development.

Also in April 2005, ERT acquired a 37.5% working interest in the Bass Lite discovery (Atwater Blocks 182, 380, 381, 425 and 426) in 7,500 feet water depth along with varying interests in 50 other blocks of exploration acreage in the eastern portion of the Atwater lease protraction area from BHP Billiton. The Bass Lite discovery contains proved undeveloped gas reserves in a sand discovered in 2001 by the Atwater 426 #1 well. In October 2005, ERT exchanged 15% of its working interest in Bass Lite for a 40% working interest in the Tiger Prospect located in Green Canyon Block 195. ERT paid $1.0 million in the exchange with no corresponding gain or loss recorded on the transaction. In December 2005, Mariner Energy elected to exercise its option to gain an additional 5% working interest. The resulting transaction leaves ERT with a 17.5% working interest in the project.

The Tiger Prospect, located at a water depth of 1,850 feet, initiated sidetrack drilling operations in May 2006. The successful well continued with completions through June 2006 and is currently waiting on flowline and umbilical installation. Production is expected to begin in October 2006.

In February 2006, ERT entered into a participation agreement with Walter Oil & Gas for a 20% interest in the Huey prospect in Garden Banks Blocks 346/390 in 1,835 feet water depth. Drilling of the exploration well began in April 2006. If successful, the development plan would consist of a subsea tieback to the Baldplate Field (Garden banks 260). Under the participation agreement, ERT has committed to pay a disproportionate share of the costs to casing point to earn the 20% interest in the potential development. ERT s share of drilling costs incurred during the six months ended June 30, 2006 was approximately $8.0 million.

As of June 30, 2006, we had incurred costs of $84.7 million and committed to an additional estimated $41.0 million for development and drilling costs related to the above property transactions.

In June 2005, ERT acquired a mature property package on the Gulf of Mexico shelf from Murphy Exploration & Production Company USA (Murphy), a wholly owned subsidiary of Murphy Oil Corporation. The acquisition cost to ERT included both cash ($163.5 million) and the assumption of the abandonment liability from Murphy of approximately $32.0 million (a non-cash investing activity). The acquisition represents essentially all of Murphy s Gulf of Mexico Shelf properties consisting of eight operated and eleven non-operated fields. ERT estimated proved reserves of the acquisition to be approximately 75 BCF equivalent. The results of the acquisition are included in the accompanying condensed consolidated statements of operations since the date of purchase. The purchase price allocation was finalized during the second quarter of 2006.

Note 4 Acquisitions

In April 2005, we agreed to acquire the diving and shallow water pipelay assets of Acergy US Inc. (formerly known as Stolt Offshore, Inc.) (Acergy) that operate in the waters of the Gulf of Mexico (GOM) and Trinidad. The transaction included: seven diving support vessels; two diving and pipelay vessels (the *Kestrel* and the *DLB 801);* a portable saturation diving system; various general diving equipment and Louisiana operating bases at the Port of Iberia and Fourchon. All of the assets are included in the Shelf Contracting segment. The transaction required regulatory approval, including the completion of a review pursuant to a Second Request from the U.S. Department of Justice. On October 18, 2005, we received clearance from the U.S. Department of Justice to close the asset purchase from Acergy. Under the terms of the clearance, we will divest one diving support vessel and have disposed of one diving support vessel and a portable saturation diving system from the combined asset package acquired through this transaction and the Torch Offshore, Inc. transaction, which closed August 31, 2005. These assets were included in assets held for sale totaling $1.0 million and $7.8 million (included in other current assets in the accompanying consolidated balance sheet) as of June 30, 2006 and December 31, 2005, respectively. On November 1, 2005, we closed the transaction to purchase the Acergy diving assets operating in the Gulf of Mexico. The assets include: seven diving support vessels, a portable saturation diving system, various general diving equipment and Louisiana operating lease at the Port of Iberia and Fourchon. We acquired the *DLB 801* in January 2006 for approximately $38.0 million and the *Kestrel* for approximately $39.9 million in March 2006 and we paid approximately $274,000 additional transaction cost related to the Acergy acquisitions in 2006.

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The Acergy acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their fair values, with the excess being recorded as goodwill. The final valuation of net assets was completed in the second quarter of 2006. The total transaction value for all of the assets was approximately $124.3 million. As of June 30, 2006, the allocation of the Acergy purchase prices was as follows (in thousands):

Vessels	$ 94,583
Goodwill	11,594
Portable saturation system and diving equipment	9,494
Facilities, land and leasehold improvements	4,314
Customer relationships intangible asset[(1)]	3,698
Materials and supplies	631
Total	$ 124,314

(1) The customer relationship intangible asset is amortized over eight years on a straight-line basis, or approximately $463,000 per year.

The results of the acquired assets are included in the accompanying condensed consolidated statements of operations since the date of the purchase. Pro forma combined operating results adjusted to reflect the results of operations of the *DLB 801* and the *Kestrel* prior to their acquisition from Acergy in January and March 2006, respectively, are not provided because the 2006 pre-acquisition results related to these vessels were immaterial.

Subsequent to our purchase of the *DLB 801,* we sold a 50% interest in the vessel in January 2006 for approximately $19.0 million. We received $6.5 million in cash in 2005 and a $12.5 million interest-bearing promissory note in 2006. We have received $9.0 million of the promissory note and expect to collect the remaining balance in the third quarter of 2006. Subsequent to the sale of the 50% interest, we entered into a 10-year charter lease agreement with the purchaser, in which the lessee has an option to purchase the remaining 50% interest in the vessel beginning in January 2009. This lease was accounted for as an operating lease. Included in our lease accounting analysis was an assessment of the likelihood of the lessee performing under the full term of the lease. The carrying amount of the *DLB 801* at June 30, 2006, was approximately $18.2 million. Minimum future rentals to be received on this lease are $69.8 million through January 2016. In addition, under the lease agreement, the lessee is able to credit $2.35 million of its lease payments per year against the remaining 50% interest in the *DLB 801* not already owned.

On November 3, 2005, we acquired Helix Energy Limited for approximately $32.7 million (approximately $27.1 million in cash, including transaction costs, and $5.6 million at time of acquisition in a two-year, variable rate note payable to certain former owners), offset by $3.4 million of cash acquired. Helix Energy Limited is an Aberdeen, UK based provider of reservoir and well technology services to the upstream oil and gas industry with offices in London, Kuala Lampur (Malaysia) and Perth (Australia). The acquisition was accounted for as a business purchase with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with the excess being recorded as goodwill. The allocation of the purchase price resulted in $8.9 million allocated to net working capital, equipment and other assets acquired, $1.1 million allocated to patented technology (to be amortized over 20 years), $6.9 million allocated to a customer-relationship intangible asset (to be amortized over 12 years), $2.4 million allocated to covenants-not-to-compete (to be amortized over 3.5 years), $6.3 million allocated to trade name (not amortized, but tested for impairment on an annual basis) and goodwill of approximately $6.6 million. Resulting amounts are included in the Contracting Services segment. The final valuation of assets acquired and liabilities assumed was completed in the first quarter of 2006. The results of Helix Energy Limited are included in the accompanying condensed consolidated statements of operations since the date of the purchase.

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In January 2006, the *Caesar* (formerly known as the *Baron*), a four year old mono-hull vessel, originally built for the cable lay market, was acquired by our subsidiary Vulcan Marine Technology LLC (Vulcan) for the Contracting Services segment for approximately $27.5 million in cash. It is currently under charter to a third-party. After completion of the charter (anticipated to end by the end of 2006), we plan to convert the vessel into a deepwater pipelay asset. The vessel is 485 feet long and already has a state-of-the-art, class 2, dynamic positioning system. The conversion program will primarily involve the installation of a conventional S lay pipelay system together with a main crane and a significant upgrade to the accommodation capability. A conversion team has already been assembled with a base at Rotterdam, The Netherlands, and the vessel is likely to enter service by mid-2007. We have entered into an agreement with the third-party currently leasing the vessel, whereby, the third-party has an option to purchase up to 49% of Vulcan for consideration totaling (i) $32.0 million cash prior to the vessel entering conversion plus its proportionate share of actual conversion costs (total conversion cost estimated to be $93 million), or (ii) once conversion begins, proportionate share (up to 49%) of total vessel and conversion costs (estimated to be $120 million). The third-party must make all contributions to Vulcan on or before December 28, 2006.

Note 5 Details of Certain Accounts (in thousands)

Other current assets consisted of the following as of June 30, 2006 and December 31, 2005:

	June 30, 2006	December 31, 2005
Other receivables	$ 2,303	$ 1,386
Prepaids	20,620	13,182
Spare parts inventory	3,512	3,628
Current deferred tax assets	11,374	8,861
Gas imbalance	3,796	3,888
Current notes receivable	5,008	1,500
Assets held for sale	1,000	7,936
Other	10,492	12,534
	$ 58,105	$ 52,915

Other assets, net, consisted of the following as of June 30, 2006 and December 31, 2005:

	June 30, 2006	December 31, 2005
Restricted cash	$ 32,587	$ 27,010
Deposits	3,415	4,594
Deferred drydock expenses	18,823	18,285
Deferred financing costs	19,697	18,714
Intangible assets with definite lives	14,934	14,707
Intangible asset with indefinite life	6,529	6,074
Other	1,428	1,490
	$ 97,413	$ 90,874

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Accrued liabilities consisted of the following as of June 30, 2006 and December 31, 2005:

	June 30, 2006	December 31, 2005
Accrued payroll and related benefits	$ 22,870	$ 27,982
Workers compensation claims	2,235	2,035
Insurance claims to be reimbursed	3,404	6,133
Royalties payable	52,245	46,555
Current decommissioning liability	15,035	15,035
Hedging liability	5,570	8,814
Income taxes payable		7,288
Deposits	3,479	10,000
Other	30,795	21,910
	$ 135,633	$ 145,752

Note 6 Equity Investments

In June 2002, we, along with Enterprise Products Partners L.P. (Enterprise), formed Deepwater Gateway, L.L.C. 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, L.L.C. totaled $117.4 million and $117.2 million as of June 30, 2006 and December 31, 2005, respectively. Further, for the six months ended June 30, 2006 and 2005, we received cash distributions from Deepwater Gateway, L.L.C. totaling $7.8 million and $13.6 million, respectively.

In December 2004, we acquired a 20% interest in Independence, an affiliate of Enterprise. Independence will own the Independence Hub platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet. Our investment was $71.3 million and $50.8 million as of June 30, 2006 and December 31, 2005, respectively, and our total investment is expected to be approximately $83 million. Further, we are 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 $397.5 million, plus applicable attorneys fees and related expenses. We have estimated the fair value of our share of the guarantee obligation to be immaterial at June 30, 2006 based upon the remote possibility of payments being made under the performance guarantee.

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 $14.1 million and $11.5 million at June 30, 2006 and December 31, 2005. 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. Effective December 31, 2003, we adopted and applied the provisions of FASB Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities,* as revised December 31, 2003, for all variable interest entities. FIN 46 requires the consolidation of variable interest entities in which an enterprise absorbs a majority of the entity s expected losses, receives a majority of the entity s expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. OTSL qualified as a variable interest entity (VIE) under FIN 46 through June 30, 2006. We have determined that we were not the primary beneficiary of OTSL and, thus, have not consolidated the financial results of OTSL. We account for our investment in OTSL under the equity method of accounting.

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Further, in conjunction with our investment in OTSL, we entered into a one year, unsecured $1.5 million working capital loan, initially bearing interest at 6% per annum, with OTSL. Interest is due quarterly beginning September 30, 2005 with a lump sum principal payment originally due to us on June 30, 2006. In July 2006, we extended the lump sum principal payment due date to September 15, 2006 and increased the interest rate to three-month LIBOR plus 4.0%.

In the first quarter of 2006, OTSL contracted 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 $6.9 million in the first quarter of 2006. The charter ended in March 2006.

Note 7 Long-Term Debt

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 second quarter of 2006, no conversion triggers were met.

Approximately 1.3 million shares and 1.2 million shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the three and six months ended June 30, 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.

As of June 30, 2006 and December 31, 2005, we estimated the fair value of our $300 million (carrying value) fixed-rate debt to be $447.0 million and $433.7 million, respectively, based upon quoted market prices.

MARAD Debt

At June 30, 2006, $133.1 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 June 30, 2006, we were in compliance with these covenants.

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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.

Revolving Credit Facilities

In August 2004, we entered into a four-year, $150 million revolving credit facility with a syndicate of banks, with Bank of America, N.A. as administrative agent and lead arranger. We cancelled this credit facility on June 30, 2006 and replaced it with a revolving credit facility that became effective on July 3, 2006 (see Note 21 below). As a result, we expensed the remaining unamortized deferred financing cost of $407,000 as of June 30, 2006.

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 (approximately $5.8 million at June 30, 2006). The notes bear interest at a LIBOR based floating rate with interest payments due quarterly beginning January 1, 2006. Principal amounts are due in November 2007.

Scheduled maturities of Long-term Debt and Capital Lease Obligations outstanding as of June 30, 2006 were as follows (in thousands):

	MARAD Debt	Convertible Senior Notes	Loan Notes	Capital Leases	Total
Less than one year	$ 3,731	$	$	$ 2,585	$ 6,316
One to two years	3,917		5,796	2,559	12,272
Two to Three years	4,113			217	4,330
Three to four years	4,318				4,318
Four to five years	4,533				4,533
Over five years	112,517	300,000			412,517
Long-term debt	133,129	300,000	5,796	5,361	444,286
Current maturities	(3,731)			(2,585)	(6,316)
Long-term debt, less current maturities	$ 129,398	$ 300,000	$ 5,796	$ 2,776	$ 437,970

We had unsecured letters of credit outstanding at June 30, 2006 totaling approximately $6.9 million. These letters of credit primarily guarantee various contract bidding and insurance activities.

We capitalized interest totaling $1.2 million and $2.4 million during the three and six months ended June 30, 2006, respectively. For the three and six months ended June 30, 2005, we capitalized interest totaling $514,000 and $587,000, respectively. We incurred interest expense of $4.9 million and $9.5 million during the three and six months ended June 30, 2006, respectively, and $4.1 million and $5.5 million during the three and six months ended June 30, 2005, respectively.

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Note 8 Income Taxes

The effective tax rate of 34% for the three and six months ended June 30, 2006, respectively, was lower than the effective rate of 36% for the same periods in 2005 due to our ability to realize foreign tax credits and oil and gas percentage depletion due to improved profitability both domestically and in foreign jurisdictions and implementation of the Internal Revenue Code section 199 manufacturing deduction as it primarily related to oil and gas production.

Note 9 Convertible Preferred Stock

On January 8, 2003, we completed the private placement of $25 million of a newly designated class of cumulative convertible preferred stock (Series A-1 Cumulative Convertible Preferred Stock, par value $0.01 per share) that is convertible into 1,666,668 shares of our common stock at $15 per share. The preferred stock was issued to a private investment firm. Subsequently in June 2004, the preferred stockholder exercised its existing right and purchased $30 million in additional cumulative convertible preferred stock (Series A-2 Cumulative Convertible Preferred Stock, par value $0.01 per share). In accordance with the January 8, 2003 agreement, the $30 million in additional preferred stock is convertible into 1,964,058 shares of Helix common stock at $15.27 per share. In the event the holder of the convertible preferred stock elects to redeem into Helix common stock and our common stock price is below the conversion prices, unless we have elected to settle in cash, the holder would receive additional shares above the 1,666,668 common shares (Series A-1 tranche) and 1,964,058 common shares (Series A-2 tranche). The incremental shares would be treated as a dividend and reduce net income applicable to common shareholders.

The preferred stock has a minimum annual dividend rate of 4%, subject to adjustment (approximately 5.85% at June 30, 2006), payable quarterly in cash or common shares at our option. We paid these dividends in 2006 and 2005 on the last day of the respective quarter in cash. The holder may redeem the value of its original and additional investment in the preferred shares to be settled in common stock at the then prevailing market price or cash at our discretion. In the event we are unable to deliver registered common shares, we could be required to redeem in cash.

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

Note 10 Hedging Activities

Our price 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. All derivatives are reflected in our balance sheet at fair value. During 2005 and the first half of 2006, we 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 of $9.6 million and $13.4 million as of June 30, 2006 and December 31, 2005, respectively. We recorded unrealized gains (losses) of approximately $(788,000) and $2.4 million, net of tax (expense) benefit of $424,000 and $(1.3 million), during the three and six months ended June 30, 2006, respectively, in accumulated other comprehensive income (loss), a component of shareholders equity, as these hedges were highly effective. For the three and six months ended June 30, 2005, we recorded $3.7 million and $6.7 million, respectively, of unrealized losses, net of tax benefit of $2.0 million and $3.6 million, respectively. During the three and six months ended June 30, 2006, we reclassified approximately $1.4 million and $6.3 million of gains, respectively, from other comprehensive income to Oil and Gas Production revenues upon the sale of the related oil and gas production. For the three and six months ended June 30, 2005, we reclassified approximately $1.7 million and $3.0 million, respectively, of losses from other comprehensive income to Oil and Gas Production revenues.

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As of June 30, 2006, we had the following volumes under derivative contracts related to our oil and gas producing activities:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
July 2006 December 2006	Collar	125 MBbl	$ 44.00 $70.48
January 2007 December 2007	Collar	50 MBbl	$ 40.00 $62.15
Natural Gas:			
July 2006 December 2006	Collar	600,000 MMBtu	$ 7.25 $13.40
January 2007 June 2007	Collar	550,000 MMBtu	$ 8.00 $13.69
July 2007 December 2007	Collar	233,333 MMBtu	$ 7.50 $10.79

We have not entered into any hedge instruments subsequent to June 30, 2006.

As of June 30, 2006, Remington Oil and Gas Corporation (Remington) had oil forward sales contracts for the period from July 2006 through June 2007. The contracts cover 50.7 MBbl per month at a weighted average price of $70.48. In addition, Remington had natural gas forward sales contracts for the period from July 2006 through June 2007. The contracts cover 733,000 MMbtu per month at a weighted average price of $9.31. These hedges do not qualify for hedge accounting.

Note 11 Foreign Currency

The functional currency for our foreign subsidiaries, Well Ops (U.K.) Limited and Helix Energy Limited, is the applicable local currency (British Pound). Results of operations for these subsidiaries are translated into U.S. dollars using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated into U.S. dollars using the exchange rate in effect at the balance sheet date, and the resulting translation adjustment, which were unrealized gains of $7.8 million and $9.0 million for the three and six months ended June 30, 2006, respectively, is included in accumulated other comprehensive income (loss), a component of shareholders equity. For the three and six months ended June 30, 2005, we recorded $5.0 million and $6.7 million, respectively, of unrealized losses in accumulated other comprehensive income relate to translation adjustment. Deferred taxes have not been provided on foreign currency translation adjustments since we consider our undistributed earnings (when applicable) of our non-U.S. subsidiaries to be permanently reinvested. All foreign currency transaction gains and losses are recognized currently in the statements of operations. These amounts for the three months and six months ended June 30, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

Canyon Offshore, Inc. (Canyon), our ROV subsidiary, has operations in the United Kingdom and Southeast Asia sectors. Canyon conducts the majority of its operations in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the statements of operations. These amounts for the three and six months ended June 30, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

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Note 12 Comprehensive Income

The components of total comprehensive income for the three and six months ended June 30, 2006 and 2005 were as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Net income	$ 69,944	$ 26,577	$ 126,137	$ 52,537
Foreign currency translation gain (loss)	7,846	(5,041)	9,006	(6,677)
Unrealized gain (loss) on commodity hedges, net	(788)	(3,683)	2,443	(6,736)
Total comprehensive income	$ 77,002	$ 17,853	$ 137,586	$ 39,124

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

	June 30, 2006	December 31, 2005
Cumulative foreign currency translation adjustment	$ 15,985	$ 6,979
Unrealized loss on commodity hedges, net	(6,265)	(8,708)
Accumulated other comprehensive income (loss)	$ 9,720	$ (1,729)

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 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 per share amounts were as follows (in thousands):

	Three Months Ended June 30, 2006		Three Months Ended June 30, 2005	
	Income	Shares	Income	Shares
Earnings applicable per common share Basic	$ 69,139	78,462	$ 26,027	77,444
Effect of dilutive securities:				
Stock options		414		696
Restricted shares		137		192
Employee stock purchase plan		4		
Convertible Senior Notes		1,317		
Convertible preferred stock	805	3,631	550	3,631
Earnings applicable per common share Diluted	$ 69,944	83,965	$ 26,577	81,963

	Six Months Ended June 30, 2006		Six Months Ended June 30, 2005	
	Income	Shares	Income	Shares
Earnings applicable per common share Basic	$ 124,528	78,216	$ 51,437	77,294
Effect of dilutive securities:				

Stock options		513		737
Restricted shares		122		188
Employee stock purchase plan		7		
Convertible Senior Notes		1,170		
Convertible preferred stock	1,609	3,631	1,100	3,631
Earnings applicable per common share Diluted	$ 126,137	83,659	$ 52,537	81,850

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There were no antidilutive stock options in the three and six months ended June 30, 2006 and 2005, respectively. Net income for the diluted earnings per share calculation for the three and six months ended June 30, 2006 and 2005 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 (the 2005 Incentive Plan) and the 1998 Employee Stock Purchase Plan (the ESPP). Under the 1995 Incentive Plan, a maximum of 10% of the total shares of common stock issued and outstanding may be granted to key executives and selected employees who are likely to make a significant positive impact on our reported net income as well as non-employee members of the Board of Directors. Following the approval by shareholders of the 2005 Incentive Plan on May 10, 2005, no further grants have been or will be made under the 1995 Plan. The aggregate number of shares that may be granted under the 2005 Incentive Plan is 6,000,000 shares (after adjustment for the December 8, 2005 two-for-one stock split) of which 4,000,000 shares may be granted in the form of restricted stock or restricted stock units and 2,000,000 shares may be granted in the form of stock options. The 1995 and 2005 Incentive Plans and the ESPP are administered by the Compensation Committee of the Board of Directors, which in the case of the 1995 and 2005 Incentive Plans, determines the type of award to be made to each participant and set forth in the related award agreement, the terms, conditions and limitations applicable to each award. The committee may grant stock options, stock and cash awards. Awards granted to employees under the 1995 and 2005 Incentive Plan typically vest 20% per year for a five-year period (or in the case of certain stock option awards under the 1995 Incentive Plan, 33% per year for a three-year period), if in the form of stock options, have a maximum exercise life of ten years and, subject to certain exceptions, are not transferable.

Prior to January 1, 2006, we used the intrinsic value method of accounting for our stock-based compensation. Accordingly, no compensation expense was recognized when the exercise price of an employee stock option was equal to the common share market price on the grant date and all other terms were fixed. In addition, under the intrinsic value method, on the date of grant for restricted shares, we recorded unearned compensation (a component of shareholders equity) that equaled the product of the number of shares granted and the closing price of our common stock on the grant date, and expense was recognized over the vesting period of each grant on a straight-line basis.

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 share-based payments and recognize compensation cost on a straight-line basis over the respective vesting period. No forfeitures were estimated for outstanding unvested options and restricted shares as historical forfeitures have been immaterial. We have selected the modified-prospective method of adoption, which requires that compensation expense be recorded for all unvested stock options and restricted stock beginning in 2006 as the requisite service is rendered. In addition to the compensation cost recognition requirements, tax deduction benefits for an award in excess of recognized compensation cost is reported as a financing cash flow rather than as an operating cash flow. The adoption did not have a material impact on our consolidated results of operations, earnings per share and cash flows. There were no stock option grants in the first half of 2006 or 2005.

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The following table reflects our pro forma results if the fair value method had been used for the accounting for these plans for the three and six months ended June 30, 2005 (in thousands, except per share amounts):

	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
Net income applicable to common shareholders:		
As Reported	$ 26,027	$ 51,437
Add back: Stock-based compensation cost included in reported net income, net of taxes	130	254
Deduct: Total stock-based compensation cost determined under the fair value method, net of tax	(594)	(1,051)
Pro Forma	$ 25,563	$ 50,640
Earnings per common share:		
Basic:		
As reported	$ 0.34	$ 0.67
Pro forma	$ 0.33	$ 0.66
Diluted:		
As reported	$ 0.32	$ 0.64
Pro forma	$ 0.32	$ 0.63

For the purposes of pro forma disclosures, the fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model. The estimated fair value of the option is amortized to pro forma expense over the vesting period.

On January 3, 2005, we granted 188,132 restricted shares to key executives and selected management employees, which vest 20% per year for a five-year period. The market value (based on the quoted price of the common stock on the business day prior to the date of the grant) of the restricted shares was $19.56 per share, or $3.7 million, at the date of the grant. The amounts granted were recorded as unearned compensation, a component of shareholders equity, and charged to expense over the respective vesting periods. Amortization of unearned compensation totaled $204,000 and $397,000 for the three and six months ended June 30, 2005, respectively. Awards are amortized directly to expense and additional paid in capital (a component of Common Stock). The balance in unearned compensation at December 31, 2005 was $7.5 million and was reversed in January 2006 upon adoption of the fair value method.

During the six months ended June 30, 2006, we made the following restricted share grants to members of our board of directors, key executives and selected management employees (market value is based on the quoted price of the common stock on the business day prior to the date of grant):

196,820 restricted shares on January 3, 2006 which vest 20% per year for a five-year period. The market value of the restricted shares was $35.89 per share, or $7.1 million, at the date of the grant;

1,705 restricted shares on March 1, 2006 which vest 20% per year for a five-year period. The market value of the restricted shares was $35.21 per share, or approximately $60,000, at the date of the grant;

10,000 restricted shares on March 20, 2006 which vest 20% per year for a five-year period. The market value of the restricted shares was $35.61 per share, or approximately $356,000, at the date of the grant;

3,207 restricted shares on April 3, 2006 which vest on January 1, 2008. The market value of the restricted shares was $37.90 per share, or approximately $122,000, at the date of the grant;

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2,140 restricted shares on May 8, 2006 which vest 20% per year for a five-year period. The market value of the restricted shares was $42.91 per share, or approximately $92,000, at the date of the grant; and

4,180 restricted shares on June 30, 2006 which vest 20% per year for a five-year period. The market value of the restricted shares was $35.92 per share, or approximately $150,000, at the date of the grant.

For the three and six months ended June 30, 2006, $1.7 million and $3.2 million, respectively, was recognized as compensation expense related to unvested stock options and restricted shares. Total compensation cost related to nonvested awards not yet recognized at June 30, 2006 is approximately $16.4 million.

Subsequent to June 30, 2006, we granted 148,665 and 24,780 restricted shares to key executives retained from Remington (see Note 21). These shares vest 60% after the third anniversary and 20 % there after for a five-year period and 50% for a two-year period, respectively. The market value of the restricted shares was $40.36 per share, or approximately $6.0 million and $1.0 million, respectively, at the date of grant. In addition, we granted 12,390 restricted shares to a new member of our Board of Directors. These shares vest 20% per year for a five-year period. The market value of the restricted shares was $40.36 per share, or approximately $500,000.

All of the options outstanding at June 30, 2006, have exercise prices as follows: 163,000 shares at $8.57; 67,510 shares at $9.32; 117,346 shares at $10.92; 73,000 shares at $10.94; 64,800 shares at $11.00; 195,320 shares at $12.18; 70,400 shares at $13.91; and 211,800 shares ranging from $8.14 to $12.00, and a weighted average remaining contractual life of 6.24 years.

Options outstanding are as follows:

	June 30, 2006		June 30, 2005	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding, Beginning of year	1,717,904	$ 10.91	2,599,894	$ 10.65
Granted		$		$
Exercised	(752,728)	$ 11.32	(664,766)	$ 10.32
Terminated	(2,000)	$ 8.14	(14,400)	$ 12.00
Options outstanding at June 30,	963,176	$ 10.60	1,920,728	$ 10.77
Options exercisable at June 30,	508,984	$ 10.40	1,191,543	$ 10.83

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. Under this plan 41,006 and 42,224 shares of common stock were purchased in the open market at a share price of $26.14 and $15.26 during the six months ended June 30, 2006 and 2005, respectively, related to the purchase periods for the second half of 2005 and 2004, respectively. In July 2006, 56,592 shares of common stock were purchased in the open market at a share price of $38.17 related to the purchase period for the first half of 2006. For the six months ended June 30, 2006, we recognized $568,000 of compensation expense related to stock purchased under the ESPP. No expenses related to the ESPP were recognized in 2005 under the intrinsic value method.

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Note 15 Stock Buyback Program

On June 28, 2006, our Board of Directors authorized the Company to discretionarily purchase up to $50 million of our common stock in the open market. The timing of any share repurchases under the program will depend on a variety of factors, including market conditions, and may be suspended and discontinued at any time. Common stock acquired through the program will be accounted for as treasury shares. As of June 30, 2006, no shares were purchased under this program.

Note 16 Business Segment Information (in thousands)

In the fourth quarter of 2005, we modified our segment reporting from three reportable segments to four reportable segments. Our operations are conducted through the following primary reportable segments: Contracting Services (formerly known as Deepwater Contracting), Shelf Contracting, Oil and Gas Production and Production Facilities. The realignment of reportable segments was attributable to organizational changes within the Company as it is related to separating Marine Contracting into two reportable segments Contracting Services and Shelf Contracting. Contracting Services operations include deepwater pipelay, well operations and robotics. Shelf Contracting operations consist of assets deployed primarily for diving-related activities and shallow water construction. See Note 20 for discussion of potential initial public offering of Cal Dive International, Inc. (CDI) common stock (represented by the Shelf Contracting segment). As a result, segment disclosures for the prior period have been restated to conform to the current period presentation. All intercompany transactions between the segments have been eliminated.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Revenues				
Contracting services	$ 112,589	$ 62,692	$ 213,620	$ 126,975
Shelf contracting	124,765	40,699	244,554	76,904
Oil and gas production	81,110	67,590	161,423	130,976
Intercompany elimination	(13,451)	(4,450)	(22,936)	(8,749)
Total	$ 305,013	$ 166,531	$ 596,661	$ 326,106
Income from operations				
Contracting services	$ 18,654	$ 3,124	$ 39,275	$ 8,388
Shelf contracting(1)	51,416	5,777	98,485	14,178
Oil and gas production	35,374	30,918	52,339	57,332
Production facilities equity investments(2)	(335)	(258)	(653)	(377)
Intercompany elimination	(997)		(997)	
Total	$ 104,112	$ 39,561	$ 188,449	$ 79,521
Equity in earnings of production facilities investments	$ 4,629	$ 2,708	$ 7,994	$ 4,437

(1) Included $(183,000) and $2.7 million equity in (loss) earnings from investment

in OTSL during the three and six months ended June 30, 2006.

(2) Represents selling and administrative expense of Production Facilities incurred by us. See Equity in Earnings of Production Facilities Investments for earnings contribution.

	June 30, 2006	December 31, 2005
Identifiable Assets		
Contracting services	$ 764,287	$ 736,852
Shelf contracting	381,477	277,446
Oil and gas production	544,462	478,522
Production facilities equity investments	190,361	168,044
Total	$ 1,880,587	$ 1,660,864

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Intercompany segment revenues during the three and six months ended June 30, 2006 and 2005 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Contracting services	$ 10,215	$ 3,939	$ 18,192	$ 8,004
Shelf contracting	3,236	511	4,744	745
Total	$ 13,451	$ 4,450	$ 22,936	$ 8,749

Intercompany segment profit during the three and six months ended June 30, 2006 and 2005 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Contracting services	$ 248	$	$ 248	$
Shelf contracting	749		749	
Total	$ 997	$	$ 997	$

During the three and six months ended June 30, 2006, we derived $33.2 million and $62.3 million, respectively, of our revenues from the U.K. sector, utilizing $185.8 million of our total assets in this region. During the three and six months ended June 30, 2005, we derived $18.0 million and $48.7 million, respectively, of our revenues from the U.K. sector utilizing $137.0 million of our total assets in this region. The majority of the remaining revenues were generated in the U.S. Gulf of Mexico.

Note 17 Related Party Transactions

In April 2000, ERT 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). The investors of this entity include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of our 20% working interest. Production began in December 2003. Payments to OKCD from ERT totaled $9.0 million and $19.4 million in the three and six months ended June 30, 2006, respectively, and $6.7 million and $13.2 million in the three and six months ended June 30, 2005, respectively.

Note 18 Commitments and Contingencies

Commitments

At June 30, 2006, we had committed to convert a certain Contracting Services vessel (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 $93 million, of which $15.2 million had been committed at June 30, 2006. In addition, we will upgrade the *Q4000* to include drilling via the addition of a modular-based drilling system for approximately $40 million, of which approximately $29.5 million had been committed at June 30, 2006.

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In December 2005, we entered into a memorandum of understanding to acquire the business of Singapore-based Fraser Diving International Ltd. (FDI) for $23.5 million. FDI owns six portable saturation diving systems and 15 surface diving systems that operate primarily in Southeast Asia and the Middle East. As a part of the proposed purchase, in December 2005, a payment of an additional $2.5 million was made to FDI for the purchase of one of the portable saturation diving systems. We also paid FDI $2.5 million and issued an irrevocable letter of credit for an additional $2.5 million to FDI that constitutes a non-refundable deposit totaling $5.0 million. The purchase of FDI was completed in July 2006.

Contingencies

We are involved in various routine legal proceedings, primarily involving claims for personal injury under the General Maritime Laws of the United States and the Jones Act as a result of alleged negligence. In addition, we, from time to time, incur other claims, such as contract disputes, in the normal course of business. In that regard, in 1998, one of our subsidiaries entered into a subcontract with Seacore Marine Contractors Limited (Seacore) to provide the *Sea Sorceress* to a Coflexip subsidiary in Canada (Coflexip). Due to difficulties with respect to the sea and soil conditions, the contract was terminated and an arbitration to recover damages was commenced. A preliminary liability finding has been made by the arbitrator against Seacore and in favor of the Coflexip subsidiary. We were not a party to this arbitration proceeding. Seacore and Coflexip settled this matter prior to the conclusion of the arbitration proceeding, with Seacore paying Coflexip $6.95 million CDN. Seacore has initiated an arbitration proceeding against Cal Dive Offshore Ltd. (CDO), a subsidiary of ours, seeking contribution for half of this amount. One of the grounds in the preliminary findings by the arbitrator is applicable to CDO, and CDO holds substantial counterclaims against Seacore.

Although the above discussed matters may have the potential for additional liability, we believe 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.

We sustained damage to certain of our oil and gas production facilities in Hurricanes *Katrina* and *Rita*. We estimate total repair and inspection costs resulting from the hurricanes will range from $5 million to $8 million net of expected insurance reimbursement. These costs, and any related insurance reimbursements, will be recorded as incurred this year.

Note 19 Recently Issued Accounting Principles

In June 2006, the FASB issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109* (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in accordance with FASB Statement No. 109, *Accounting for Income Taxes* (SFAS No. 109). FIN 48 clarifies the application of SFAS No. 109 by defining criteria that an individual tax position must meet for any part of the benefit of that position to be recognized in the financial statements. Additionally, FIN 48 provides guidance on the measurement, derecognition, classification and disclosure of tax positions, along with accounting for the related interest and penalties. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are currently evaluating the impact the adoption of FIN 48 will have on our financial position, results of operations and cash flows.

Note 20 Pending Transaction

On May 31, 2006, we announced that CDI, a wholly owned subsidiary of the Company, filed a Registration Statement on Form S-1 with the SEC for the initial public offering of a minority interest in CDI s common stock. An amended Form S-1 was subsequently filed on July 7, 2006. CDI represents our Shelf Contracting segment that provides manned diving, pipelay and pipe burial services to the offshore oil and natural gas industry. The amended registration statement has not yet become effective. These securities may not be sold nor may offers to buy be accepted prior to the time the amended registration statement becomes effective.

Note 21 Subsequent Event

Remington Acquisition

As of July 1, 2006, we effected the acquisition of Remington, an independent oil and gas exploration and production company headquartered in Dallas, Texas, with operations concentrating in the onshore and offshore regions of the Gulf Coast, for approximately $1.4 billion in cash and stock. 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 shareholders and funded the cash portion of the Remington acquisition (approximately $807.7 million) through a credit agreement (see below).

The cash portion of the merger consideration was financed from borrowings under a credit agreement we entered into in conjunction with the merger. 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 party thereto (collectively, the Lenders), pursuant to which we borrowed $835 million in a term loan (the Term Loan) and may borrow revolving loans (the Revolving Loans) under a revolving credit facility up to an outstanding amount of $300 million (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.

Senior Credit Facilities

The Term Loan and the Revolving Loans (together, the Loans) will, at our election, bear interest either in relation to Bank of America s base rate or to a LIBOR rate (current selection based on LIBOR). The Term Loan or portions thereof bearing interest at the base rate will bear interest at a per annum rate equal to the base rate plus 1.00% until the date our issuer rating from S&P is at least BB- and our corporate family rating from Moody s is at least B1, and, from and after that date, the base rate plus 0.75%. The Term Loan or portions thereof bearing interest at a LIBOR rate will bear interest at a per annum rate equal to the LIBOR rate selected by us plus 2.00% until the date the our issuer rating from S&P is at least BB- and our corporate family rating from Moody s is at least B1, and, from and after that date, the LIBOR rate selected by us plus 1.75%.

The Revolving Loans or portions thereof bearing interest at the base rate will bear interest at a per annum rate equal to the base rate plus a margin ranging from 0.00% to 1.25%. The Revolving Loans or portions thereof bearing interest at a LIBOR rate will bear interest at the LIBOR rate selected by us plus a margin ranging from 1.00% to 2.25%. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio provided for in the Credit Agreement.

The Term Loan matures on July 1, 2013 and is subject to scheduled principal payments of $2.1 million quarterly, starting September 30, 2006, and are subject to adjustment for any prepayments on the Term Loan. 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. In addition, upon the occurrence of certain dispositions or the issuances or incurrences of certain types of indebtedness, we may be required to prepay a portion of the Loans equal to the amount of proceeds received from such occurrences. Such prepayments will be applied first to the Term Loan, and any excess will be applied to the Revolving Loans, but will not reduce the available amount under the Revolving Credit Facility.

The Credit Agreement and the other documents entered into in connection with the Credit Agreement (together, the Loan Documents) include terms, conditions and covenants that we consider customary for this type of transaction. The covenants include restrictions on our and our subsidiaries ability to grant liens, incur indebtedness, make investments, merge or consolidate, sell or transfer assets and pay dividends. The credit facility also places certain annual and aggregate limits on expenditures for acquisitions, investments in joint ventures and capital expenditures. Finally, the Credit Agreement requires us to meet minimum financial ratios for interest coverage, consolidated leverage and, until we achieve investment grade ratings from S&P and Moody s, collateral coverage.

If we or any of our subsidiaries do not pay any amounts owed to the Lenders under the Loan Documents when due, breach any other covenant to the Lenders or fail to pay other debt above a stated threshold, in each case, subject to applicable cure periods, then the Lenders have the right to stop making advances to us and to declare the Loans immediately due. The Credit Agreement includes other events of default that are customary for this type of transaction.

The Loans and our other obligations to the Lenders under the Loan Documents are guaranteed by all of our U.S. subsidiaries. In addition, those Loans and obligations are secured by a lien on substantially all of our assets and properties and all of the assets and properties of our U.S. subsidiaries, including substantially all of the assets and properties acquired by us from Remington. The liens on the assets and properties of CDI and its subsidiaries securing the Loans will automatically be released, and its and their obligations under the Loan Documents will automatically be released, upon the initial public offering of a minority interest in CDI common stock as described in Note 20 above. Dispositions of the equity interest of CDI and the transfer of CDI related assets from us and our subsidiaries to CDI or its subsidiaries (whether prior to, contemporaneously with, or after the initial public offering) are permitted transfers under the Credit Agreement. If the initial public offering is not completed by October 31, 2006, then we will be required to provide mortgages on CDI s properties no later than January 31, 2007. In the event the initial public offering is consummated, the Lenders will retain a lien on the shares of CDI owned by Helix.

Transfer to New York Stock Exchange

Effective July 18, 2006, our common stock was no longer quoted on the NASDAQ and was listed and began trading on the New York Stock Exchange under the ticker symbol HLX.

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

FORWARD-LOOKING STATEMENTS AND ASSUMPTIONS

This Quarterly Report on Form 10-Q contains forward-looking statements that involve risks, uncertainties and assumptions that could cause our results to differ materially from those expressed or implied by such forward-looking statements. All statements, other than statements of historical fact, are statements that could be deemed forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, including, without limitation, any projections of revenue, gross margin, expenses, earnings or losses from operations, or other financial items; future production volumes, results of exploration, exploitation, development, acquisition and operations expenditures, and prospective reserve levels of property or wells; any statements of the plans, strategies and objectives of management for future operations; any statement concerning developments, performance or industry rankings relating to services; any statements regarding future economic conditions or performance; any statements of expectation or belief; any statements regarding the anticipated results (financial or otherwise) of the merger of Remington Oil and Gas Corporation into a wholly owned subsidiary of Helix; and any statements of assumptions underlying any of the foregoing. The risks, uncertainties and assumptions referred to above include the performance of contracts by suppliers, customers and partners; employee management issues; complexities of global political and economic developments, other risks described under the heading Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2005 and in Item 1A of Part II of this report on Form 10-Q; and, with respect to the Remington merger, actual results could differ materially from our expectations depending on factors such as the combined company s cost of capital; the ability of the combined company to identify and implement cost savings, synergies and efficiencies in the time frame needed to achieve these expectations; prior contractual commitments of the combined companies and their ability to terminate these commitments or amend, renegotiate or settle the same; the combined company s actual capital needs; the absence of any material incident of property damage or other hazard that could affect the need to make capital expenditures; any unforeseen merger or acquisition opportunities that could affect capital needs; the costs incurred in implementing synergies; and the factors that generally affect both Helix s and Remington s respective businesses. Actual actions that the combined company may take may differ from time to time as the combined company may deem necessary or advisable in the best interest of the combined company and its shareholders to attempt to achieve the successful integration of the companies, the synergies needed to make the transaction a financial success and to react to the economy and the combined company s market for its exploration and production. We assume no obligation and do not intend to update these forward-looking statements.

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 to be Critical Accounting Policies and Estimates as disclosed in our Form 10-K for the year ended December 31, 2005.

Recently Issued Accounting Principles

In June 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109. FIN 48 clarifies the application of SFAS No. 109 by defining criteria that an individual tax position must meet for any part of the benefit of that position to be recognized in the financial statements. Additionally, FIN 48 provides guidance on the measurement, derecognition, classification and disclosure of tax positions, along with accounting for the related interest and penalties. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We are currently evaluating the impact the adoption of FIN 48 will have on our financial position, results of operations and cash flows.

RESULTS OF OPERATIONS

In the fourth quarter of 2005, we modified our segment reporting from three reportable segments to four reportable segments. Our operations are conducted through the following primary reportable segments: Contracting Services (formerly known as Deepwater Contracting), Shelf Contracting, Oil and Gas Production and Production Facilities. The realignment of reportable segments was attributable to organizational changes within the Company as it is related to separating Marine Contracting into two reportable segments Contracting Services and Shelf Contracting. Contracting Services operations include deepwater pipelay, well operations and robotics. Shelf Contracting operations consist of assets deployed primarily for manned diving and shallow water pipelay and pipe burial services. See Note 20 for discussion of potential initial public offering of CDI common stock (represented by the Shelf Contracting segment). As a result, segment disclosures for the prior period have been restated to conform to the current period presentation. All intercompany transactions between the segments have been eliminated.

The following table sets forth for the periods presented vessel utilization rates for each of the major categories of our fleet, the average U.S. natural gas and oil prices and oil and gas production volumes (in thousands, except percentages and prices):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Our average vessel utilization rate(1):				
Contracting Services:				
Pipelay:	85%	91%	91%	87%
Well operations	83%	49%	77%	72%
Remotely operated vehicles	67%	68%	68%	68%
Shelf Contracting	87%	54%	89%	81%
U.S. natural gas prices(2)	$ 6.53	$ 6.94	$ 7.14	$ 6.67
NYMEX oil prices(3)	$70.70	$53.17	$ 67.09	$ 51.51
Gas production volume (Mcf)	4,601	4,565	9,355	9,640
Price per Mcf	$ 7.42	$ 7.32	$ 8.49	$ 6.96
Oil production volume (Bbls)	642	716	1,197	1,375
Price per Bbl	$64.98	$45.96	$ 62.07	$ 45.03
Total production (Mcfe)	8,453	8,858	16,535	17,887
Price per (Mcfe)	$ 8.97	$ 7.49	$ 9.29	$ 7.21

(1) 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 days in the applicable period.

(2) Quarterly average of the Henry Hub natural gas daily average spot price (the midpoint index price per Mmbtu for deliveries into a specific pipeline for the applicable calendar day as reported by Platts Gas Daily in the Daily Price Survey table).

(3) Quarterly average of NYMEX West Texas Intermediate near month crude oil daily average contract price.

Comparison of Three Months Ended June 30, 2006 and 2005

Net Revenues. Of the overall $138.5 million increase in revenues, $43.6 million was generated by the Contracting Services segment, $81.3 million by the Shelf Contracting segment and $13.6 million generated by the Oil and Gas Production segment. Contracting Services revenues increased primarily due to improved market demand (resulting in significantly improved contract pricing for the Pipelay and ROV divisions) and the addition of the *Express* acquired from Torch in August 2005 and the Helix Energy Limited acquisition in November 2005. In addition, Well Operations utilization is significantly higher in the second quarter of 2006 as compared to 2005 due to unscheduled downtime in the second quarter of 2005. Shelf Contracting revenues increased due to improved market demand, much of which continues to be the result of damages sustained in the 2005 hurricanes in the Gulf of Mexico. This resulted in significantly improved utilization rates and contract pricing for all divisions within the Shelf Contracting segment. Further, Shelf Contracting s revenues increased in the three months ended June 30, 2006 compared with 2005 directly as a result of the acquisition of the Torch and Acergy vessels in the third and fourth quarters of 2005. Revenues derived from assets purchased in these acquisitions were $62.8 million in the second quarter of 2006.

Oil and Gas Production revenue increased $13.6 million, or 20%, during the three months ended June 30, 2006 compared with the prior year period. The increase was primarily due to increases in oil and natural gas prices realized. The average realized oil price, net of hedges in place, during the second quarter of 2006 was 41% higher than the price realized in 2005, while average realized gas prices, net of hedges in place, increased one percent in the second quarter of 2006 compared with 2005. These increases were partially offset by a production decrease of 5% primarily due to the continuous maturation of our oil and gas properties and our inability to perform further well exploitation work due to the effects of Hurricanes *Katrina* and *Rita*.

Gross Profit. Gross profit of $131.7 million for the three months ended June 30, 2006 represented a 151% increase compared to the $52.4 million recorded in the comparable prior year period. Contracting Services gross profit increased to $30.0 million for the three months ended June 30, 2006, from $8.0 million in the second quarter of 2005. The increase was primarily attributable to improved utilization rates, improved contract pricing for the Pipelay and ROV divisions, the addition of the *Express* for the full second quarter 2006 and gross profit contribution from the Helix Energy Limited acquisition in November 2005. Shelf Contracting gross profit increased to $60.2 million for the three months ended June 30, 2006, from $8.8 million in the second quarter of 2005. As previously discussed, the increase was primarily attributable to the Torch and Acergy acquisitions, improved utilization rates and increased average contract pricing. Gross profit derived from assets purchased in these acquisitions was $33.1 million in the three months ended June 30, 2006.

Oil and Gas Production gross profit increased $5.9 million, to $41.5 million, due primarily to higher commodity prices. These increases were partially offset by lower production volumes and inspection and repair costs of approximately $5.5 million as a result of Hurricanes *Katrina* and *Rita.* In addition, gross profit in the comparable prior year period was negatively impacted by a $2.8 million write-off of remaining basis in a property which ceased production during the second quarter of 2005.

Gross margins in the second quarter of 2006 were 43% as compared to 31% in the comparable prior year period. Contracting Services margins increased 15 points to 29% in second quarter 2006 compared with 14% in the prior year period, Shelf Contracting margins increased 28 points to 50% in second quarter 2006 from 22% in the prior year period and Oil and Gas Production margins decreased 2 points to 51% in the second of quarter 2006 from 53% in the same period in 2005, due to the factors noted above.

We sustained damage to certain of our oil and gas production facilities in Hurricanes *Katrina* and *Rita*. Although our oil and gas production is currently at or near pre-hurricane levels, we continue to incur repair and inspection costs. Our estimate of total repair and inspection costs resulting from the hurricanes will range from $5 million to $8 million, net of expected insurance reimbursement. These costs, and any related insurance reimbursements, will be recorded as incurred over the next year.

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Selling and Administrative Expenses. Selling and administrative expenses of $27.4 million for the three months ended June 30, 2006 were $14.6 million higher than same period in 2005. The increase was due primarily to higher overhead to support our growth and incentive compensation accruals due to increased profitability. Selling and administrative expenses at 9% of revenues for the second quarter of 2006 was slightly higher than the 8% in second quarter 2005.

Equity in Earnings of Investments. Equity in earnings of our 50% investment in Deepwater Gateway, L.L.C. increased to $4.6 million in second quarter 2006 compared with $2.7 million in second quarter 2005. This increase is partially offset by equity loss of $183,000 from our 40% minority ownership interest in OTSL in the second quarter 2006. We acquired our equity interest in OTSL in July 2005.

Net Interest Expense and Other. We reported other expense of $3.0 million for the three months ended June 30, 2006 compared to other expense of $913,000 in the prior year period. Net interest expense of $3.2 million in second quarter 2006 was higher than the $664,000 incurred in second quarter 2005 due primarily to higher interest income in the second quarter of 2005 as a result of higher average cash balances in 2005. In addition, interest expense was higher in the second quarter of 2006 because we expensed the remaining unamortized deferred financing costs of $407,000 related to our $150 million revolving credit facility that was cancelled in June 2006. Offsetting the increase in interest expense was $1.2 million of capitalized interest in second quarter 2006, compared with $514,000 in second quarter 2005, which related primarily to our investment in Independence Hub.

Provision for Income Taxes. Income taxes increased to $35.9 million for the three months ended June 30, 2006 compared to $14.8 million in the prior year period, primarily due to increased profitability. The effective tax rate of 34% in second quarter 2006 was lower than the 36% effective tax rate for second quarter 2005 due to our ability to realize foreign tax credits and oil and gas percentage depletion due to improved profitability both domestically and in foreign jurisdictions and implementation of the Internal Revenue Code section 199 manufacturing deduction as it primarily related to oil and gas production.

Comparison of Six Months Ended June 30, 2006 and 2005

Net Revenues. Of the overall $270.6 million increase in revenues, $76.5 million was generated by the Contracting Services segment, $163.7 million by the Shelf Contracting segment and $30.4 million by the Oil and Gas Production segment. Contracting Services revenues increased primarily due to improved market demand (resulting in improved utilization rates and contract pricing for the Pipelay and Well Operations divisions, and improved contract pricing for the ROV division) and the addition of the *Express* acquired from Torch 2005 and Helix Energy Limited in 2005. Shelf Contracting revenues increased primarily as a result of the Torch and Acergy acquisitions. Revenues derived from assets purchased in these acquisitions were $110.5 million in the first half of 2006. In addition, revenue increased due to improved market demand, much of which continues to be the result of damages sustained in the 2005 hurricanes in the Gulf of Mexico. This resulted in significantly improved utilization rates and contract pricing for all divisions within the Shelf Contracting segment.

Oil and Gas Production revenue increased $30.4 million, or 23%, during the six months ended June 30, 2006 compared with the prior year period. The increase was primarily due to increases in oil and natural gas prices realized. The average realized natural gas price, net of hedges in place, during the first half of 2006 was 22% higher than the price realized in 2005. Average realized oil prices, net of hedges in place, increased 38% compared with the average price realized in the same period in 2005. These increases were partially offset by a production decrease of 8% primarily due to production shut-ins due to Hurricanes *Katrina* and *Rita*. However, oil and gas production is currently at or near pre-hurricane levels.

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Gross Profit. Gross profit of $234.0 million for the six months ended June 30, 2006 represented a 124% increase compared to the $104.3 million recorded in the comparable prior year period. Contracting Services gross profit increased to $59.5 million for the six months ended June 30, 2006, from $17.9 million in the first half of 2005. The increase was primarily attributable to improved utilization rates and contract pricing for the Pipelay and Well Operations divisions, including the contribution of the *Express* for the full first half of 2006, and improved contract pricing for the ROV division.

Shelf Contracting gross profit increased to $110.4 million for the six months ended June 30, 2006, from $19.9 million in the first half of 2005. As previously discussed, the increase was primarily attributable to additional gross profit derived from the Torch and Acergy acquisitions and improved utilization rates and contract pricing for all divisions within the segment. Gross profit derived from assets purchased in these acquisitions was $54.3 million for the six months ended June 30, 2006.

Oil and Gas Production gross profit decreased slightly from $66.5 million to $64.1 million. Gross profit decreased primarily due to a $20.7 million charge to cost of sales for our exploratory drilling costs related to the Tulane prospect as a result of mechanical difficulties experienced in the drilling of this well. The well was subsequently plugged and abandoned. Oil and Gas Production gross profit also decreased due to lower production volumes. Further, we expensed inspection and repair costs of approximately $8.9 million as a result of Hurricanes *Katrina* and *Rita*, partially offset by $2.7 million in insurance recoveries. These decreases were partially offset by higher commodity prices realized.

Gross margins in the first half of 2006 were 39% as compared to 32% in the comparable prior year period. Contracting Services margins increased 15 points to 30% in six months ended June 30, 2006 compared with 15% in the prior year period, and Shelf Contracting margins increased 20 points to 46% in first half of 2006 from 26% in the prior year period. The increases were due to the factors noted above. In addition, margins in the Oil and Gas Production segment decreased 11 points to 40% in the six months ended June 30, 2006 from 51% in the same period in 2005, primarily due to the Tulane charge. Oil and Gas Production gross margins in 2005 were impacted by impairment analysis on certain properties which resulted in $4.4 million of impairments and expensed well work and $4.5 million of expensed seismic data purchased for ERT s offshore property acquisitions.

Selling and Administrative Expenses. Selling and administrative expenses of $48.4 million for the six months ended June 30, 2006 were $22.7 million higher than the $25.7 million incurred in the six months ended June 30, 2005 due primarily to increased overhead to support our growth and incentive compensation accruals due to increased profitability. Selling and administrative expenses was at 8% of revenues for both the first half of 2006 and 2005.

Equity in Earnings of Investments. Equity in earnings of our 50% investment in Deepwater Gateway, L.L.C. increased to $8.0 million for the six months ended June 30, 2006 compared with $4.4 million in the first half of 2005. Further, equity in earnings from our 40% minority ownership interest in OTSL for the six months ended June 30, 2006 totaled approximately $2.7 million compared with $0 in the first half of 2005.

Net Interest Expense and Other. We reported other expense of $5.4 million for the six months ended June 30, 2006 compared to other expense of $2.1 million in the prior year period. Net interest expense of $5.7 million for the six months ended June 30, 2006 was higher than the $2.0 million incurred in the same period in 2005 due primarily to higher levels of debt associated with our $300 million Convertible Senior Notes which closed in March 2005 and higher interest income in 2005 due to higher average cash balances in the prior year. Offsetting the increase in interest expense was $2.4 million of capitalized interest in first half of 2006, compared with capitalized interest of $587,000 in the prior year period, which related primarily to our investment in Independence Hub.

Provision for Income Taxes. Income taxes increased to $65.0 million for the six months ended June 30, 2006 compared to $29.3 million in the prior year period, primarily due to increased profitability. The effective tax rate of 34% in the first half of 2006 was lower than the 36% effective tax rate for the first half of 2005 due to our ability to realize foreign tax credits and oil and gas percentage depletion due to improved profitability both domestically and in foreign jurisdictions and implementation of the Internal Revenue Code section 199 manufacturing deduction as it primarily related to oil and gas production.

LIQUIDITY AND CAPITAL RESOURCES

Total debt as of June 30, 2006 was $444.3 million comprised primarily of $300 million of Convertible Senior Notes which mature in 2025 and $133.1 million of MARAD debt which matures in 2027. In addition, as of June 30, 2006, we had $32.6 million of unrestricted cash. On July 3, 2006, we entered into the Credit Agreement, in which we borrowed $835 million under a term loan and may borrow under a revolving credit facility up to $300 million. Proceeds from the Credit Agreement were used to fund the cash portion of the Remington acquisition and pay related transaction costs. See further discussion below under Financing Activities. For a discussion of expected uses of our cash related to our exploration and development of our deepwater prospects, see Investing Activities below.

In addition, on June 28, 2006, our Board of Directors authorized the Company to discretionarily purchase up to $50 million of our common stock in the open market. The timing of any share repurchases under the program will depend on a variety of factors, including market conditions, and may be suspended and discontinued at any time. Common stock acquired through the program will be accounted for as treasury shares. As of June 30, 2006, no shares were purchased under this program.

Hedging Activities. Our price risk management activities involve the use of derivative financial instruments to hedge the impact of market price risk exposures primarily related to the our oil and gas production. All derivatives are reflected in our balance sheet at fair value.

During 2005 and the first half of 2006, we entered into various cash flow hedging costless collars 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 of $9.6 million and $13.4 million as of June 30, 2006 and December 31, 2005, respectively. We recorded unrealized gains (losses) of approximately $(788,000) and $2.4 million, net of tax (expense) benefit of $424,000 and $(1.3 million), during the three and six months ended June 30, 2006, respectively, in accumulated other comprehensive income (loss), a component of shareholders equity, as these hedges were highly effective. For the three and six months ended June 30, 2005, we recorded $3.7 million and $6.7 million, respectively, of unrealized losses, net of tax benefit of $2.0 million and $3.6 million, respectively. During the three and six months ended June 30, 2006, we reclassified approximately $1.4 million and $6.3 million of gains, respectively, from other comprehensive income to Oil and Gas Production revenues upon the sale of the related oil and gas production. For the three and six months ended June 30, 2005, we reclassified approximately $1.7 million and $3.0 million, respectively, of losses from other comprehensive income to Oil and Gas Production revenues.

As of June 30, 2006, Remington had oil forward sales contracts for the period from July 2006 through June 2007. The contracts cover 50.7 MBbl per month at a weighted average price of $70.48. In addition, Remington had natural gas forward sales contracts for the period from July 2006 through June 2007. The contracts cover 733,000 MMbtu per month at a weighted average price of $9.31. These hedges do not qualify for hedge accounting.

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Operating Activities. The increase in cash flow from operations for the six months ended June 30, 2006 as compared to the same period in 2005 was due primarily to an increase in profitability ($73.6 million), which included a non-cash asset impairment charge of $20.7 million and deferred taxes of $29.1 million. These increases were partially offset by increases in accounts receivable primarily due to increased revenues for the six months ended June 30, 2006 as compared to 2005 in the Contracting Services and Shelf Contracting segments and decreases in accounts payable and accrued liabilities (due primarily to incentive compensation payments, timing of trade accounts payable and a decrease in hedge liability accruals). In addition, cash from operations was negatively impacted by the reclassification of our excess tax benefits related to the exercise of stock options and vesting of restricted shares from operating activities to financing activities in the first half of 2006 as a result of our adoption of the Statement of Financial Accounting Standards No. 123 (Revised 2004) *Share-Based Payment* (SFAS No. 123R).

Investing Activities. Included in the capital acquisitions and expenditures during the first half of 2006 was $63.0 million for ERT well exploitation programs, further *Gunnison* field development and other deepwater development costs, and $54.4 million related to our Contracting Services segment (including $27.5 million for the purchase of the *Caesar*). Further, we completed the Acergy acquisition for the Shelf Contracting segment with the purchase of the *DLB 801* and the *Kestrel* for approximately $78.2 million (inclusive of $274,000 transaction costs paid in 2006). Included in the capital expenditures during the first six months of 2005 was $163.5 million for the Murphy properties acquisition by ERT, $34.8 million for ERT well exploitation programs and further *Gunnison* field development, $6.3 million for Canyon Offshore ROV and trencher systems and approximately $8.2 million for vessel upgrades on certain Contracting Services and Shelf Contracting vessels.

As of June 30, 2006, we have the following investments that are accounted for under the equity method of accounting: Deepwater Gateway, L.L.C., Independence Hub, LLC (Independence) and Offshore Technology Solutions Limited (OTSL):

Deepwater Gateway, L.L.C. We, along with Enterprise Products Partners L.P. (Enterprise), formed Deepwater Gateway, L.L.C. (a 50/50 venture) to design, construct, install, own and operate a TLP production hub primarily for Anadarko Petroleum Corporation s *Marco Polo* field discovery in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway, L.L.C. totaled $117.4 million as of June 30, 2006.

Independence Hub, LLC. In December 2004, we acquired a 20% interest in Independence, an affiliate of Enterprise. Independence will own the Independence Hub platform to be located in Mississippi Canyon block 920 in a water depth of 8,000 feet. Our investment in Independence Hub LLC (Independence) was $71.3 million as of June 30, 2006, and our total investment is expected to be approximately $83 million. We expect to complete our investment by the end of 2006.

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 $14.1 million at June 30, 2006. 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 entered into a one year, unsecured $1.5 million working capital loan, initially bearing interest at 6% per annum, with OTSL. Interest is due quarterly beginning September 30, 2005 with a lump sum principal payment originally due to us on June 30, 2006. In July 2006, we extended the lump sum principal payment due date to September 15, 2006 and increased the interest rate to three-month LIBOR plus 4.0%. In the first quarter of 2006, OTSL contracted 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 $6.9 million during the first quarter of 2006. The charter ended in March 2006.

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We made the following contributions to our equity investments during the six months ended June 30, 2006 and 2005 (in thousands):

	Six Months Ended June 30,	
	2006	2005
Deepwater Gateway, L.L.C.[1]	$	$ 72,000
Independence Hub, LLC	19,019	23,564
OTSL		
Total	$ 19,019	$ 95,564

(1) Contribution made in the six months ended June 30, 2005 related to Deepwater Gateway, L.L.C. was for the repayment of our portion of the term loan for Deepwater Gateway, L.L.C. Upon repayment of the loan, our $7.5 million restricted cash in 2005 was released from escrow and the escrow agreement was terminated.

We received the following distributions from our equity investments during the six months ended June 30, 2006 and 2005 (in thousands):

	Six Months Ended June 30,	
	2006	2005
Deepwater Gateway, L.L.C	$ 7,750	$ 13,600
Independence Hub, LLC		
OTSL	68	
Total	$ 7,818	$ 13,600

Oil and Gas Production

As of June 30, 2006, we had $32.6 million of restricted cash, included in other assets, net, in the accompanying condensed consolidated balance sheet, all of which related to ERT s escrow funds for decommissioning liabilities associated with the SMI 130 field acquisitions in 2002. Under the purchase agreement for the acquisitions ERT is obligated to escrow 50% of production up to the first $20 million and 37.5% of production on the remaining balance up to $33 million in total escrow. ERT may use the restricted cash for decommissioning the related fields.

In April 2000, ERT 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), the investors of which include current and former Helix senior management, in exchange for a revenue interest that is an overriding royalty interest of 25% of our 20% working interest. Production began in December 2003. Payments to OKCD from ERT totaled $9.0 million and $19.4 million in the three and six months ended June 30, 2006, respectively, and $6.7 million and $13.2 million in the three and six months ended June 30, 2005, respectively.

As an extension of ERT s well exploitation and PUD strategies, ERT 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. The total estimated cost to us of approximately $20.7 million was charged to earnings in the first quarter of 2006. We continue to evaluate various options with the operator for recovering the potential reserves. Approximately $5.5 million of the equipment was redeployed and remains capitalized.

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In March 2005, ERT acquired a 30% working interest in a proven undeveloped field in Atwater Block 63 (Telemark) of the Deepwater Gulf of Mexico for cash and assumption of certain decommissioning liabilities. In December 2005, ERT was advised by Norsk Hydro USA Oil and Gas, Inc. (Norsk Hydro) that Norsk Hydro will not pursue their development plan for the deepwater discovery. As a result, ERT acquired a 100% working interest and operatorship in April 2006 following a non-consent to the ERT plan of development by Norsk Hydro. ERT s interest in this property and surrounding developments were sold in July 2006 for $15 million in cash and with ERT retaining a reservation of an overriding royalty interest in the Telemark development.

In April 2005, ERT entered into a participation agreement to acquire a 50% working interest in the Devil s Island discovery (Garden Banks Block 344 E/2) in 2,300 feet water depth. This deepwater development is operated by Hess. An appraisal well was drilled in April 2006 and was suspended. A new sidetrack well completion plan is currently under review. Participation in the additional sidetrack will require an amended participation agreement which is currently under negotiation with Hess. The field will ultimately be developed via a subsea tieback to Baldpate Field (Garden Banks Block 260). Under the participation agreement, ERT will pay 100% of the drilling costs and a disproportionate share of the development costs to earn a 50% working interest in the field. Our Contracting Services assets would participate in this development.

Also in April 2005, ERT acquired a 37.5% working interest in the Bass Lite discovery (Atwater Blocks 182, 380, 381, 425 and 426) in 7,500 feet water depth along with varying interests in 50 other blocks of exploration acreage in the eastern portion of the Atwater lease protraction area from BHP Billiton. The Bass Lite discovery contains proved undeveloped gas reserves in a sand discovered in 2001 by the Atwater 426 #1 well. In October 2005, ERT exchanged 15% of its working interest in Bass Lite for a 40% working interest in the Tiger Prospect located in Green Canyon Block 195. ERT paid $1.0 million in the exchange with no corresponding gain or loss recorded on the transaction. In December 2005, Mariner Energy elected to exercise its option to gain an additional 5% working interest. The resulting transaction leaves ERT with a 17.5% working interest in the project.

The Tiger Prospect, located at a water depth of 1,850 feet, initiated sidetrack drilling operations in May 2006. The successful well continued with completions through June 2006 and is currently waiting on flowline and umbilical installation. Production is expected to begin in October 2006.

In February 2006, ERT entered into a participation agreement with Walter Oil & Gas for a 20% interest in the Huey prospect in Garden Banks Blocks 346/390 in 1,835 feet water depth. Drilling of the exploration well began in April 2006. If successful, the development plan would consist of a subsea tieback to the Baldplate Field (Garden banks 260). Under the participation agreement, ERT has committed to pay a disproportionate share of the costs to casing point to earn the 20% interest in the potential development. ERT s share of drilling costs incurred during the six months ended June 30, 2006 was approximately $8.0 million.

As of June 30, 2006, we had incurred costs of $84.7 million and committed to an additional estimated $41 million for development and drilling costs related to the above property transactions.

In June 2005, ERT acquired a mature property package on the Gulf of Mexico shelf from Murphy Exploration & Production Company USA (Murphy), a wholly owned subsidiary of Murphy Oil Corporation. The acquisition cost to ERT included both cash ($163.5 million) and the assumption of the abandonment liability from Murphy of approximately $32.0 million (a non-cash investing activity). The acquisition represents essentially all of Murphy s Gulf of Mexico Shelf properties consisting of eight operated and eleven non-operated fields. ERT estimated proved reserves of the acquisition to be approximately 75 BCF equivalent. The results of the acquisition are included in the accompanying condensed consolidated statements of operations since the date of purchase. The purchase price allocation was finalized as of during the second quarter of 2006.

As of July 1, 2006, we effected the acquisition of Remington for approximately $1.4 billion in cash and common stock, which resulted in Remington becoming a wholly owned subsidiary of the Company. Under the merger, each share of common stock, par value $0.01 per share, of Remington was converted into the right to receive $27.00 in cash and 0.436 shares of our common stock. In July 2006, we issued 13,032,528 shares of our common stock and funded the cash portion of the Remington acquisition (approximately $807.7 million) through a credit agreement (see Note 21 and below). A detailed description of this transaction is set forth in our registration statement on Form S-4 (Reg. No. 333-132922).

Shelf Contracting

Also in April 2005, we agreed to acquire the diving and shallow water pipelay assets of Acergy that currently operate in the waters of the Gulf of Mexico (GOM) and Trinidad. On November 1, 2005, we closed the transaction to purchase the diving assets of Acergy that operate in the Gulf of Mexico. In addition, separate agreements to purchase the *DLB 801* and *Kestrel* were closed in the first quarter of 2006 when these assets completed their work campaigns in Trinidadian waters. The *DLB 801* was purchased in January 2006 for approximately $38.0 million. We subsequently sold a 50% interest in this vessel in January 2006 for approximately $19.0 million. We received $6.5 million in cash in 2005 and a $12.5 million interest-bearing promissory note in 2006. We have received $9.0 million of the promissory note and expect to collect the remaining balance in the third quarter of 2006. Subsequent to the sale of the 50% interest, we entered into a 10-year charter lease agreement with the purchaser, in which the lessee has an option to purchase the remaining 50% interest in the vessel beginning in January 2009. This lease was accounted for as an operating lease. Included in our lease accounting analysis was an assessment of the likelihood of the lessee performing under the full term of the lease. The carrying amount of the *DLB 801* at June 30, 2006, was approximately $18.2 million. Minimum future rentals on this lease are $69.8 million over the next ten years through January 2016. In addition, under the lease agreement, the lessee is able to credit $2.35 million of its lease payments per year against the remaining 50% interest in the *DLB 801* not already owned.

Contracting Services

In January 2006, one of our subsidiaries, Vulcan Marine Technology LLC, purchased the *Caesar* for the Contracting Services segment for approximately $27.5 million in cash. It is currently under charter to a third-party. After completion of the charter (anticipated to end by the end of 2006), we plan to convert the vessel into a deepwater pipelay asset. Total conversion costs are estimated to be approximately $93 million, of which $15.2 million had been committed at June 30, 2006. We have entered into an agreement with the third-party currently leasing the vessel, whereby, it has an option to purchase up to 49% of Vulcan for consideration totaling (i) $32.0 million cash prior to the vessel entering conversion plus its proportionate share of actual conversion costs (estimated to be $93 million), or (ii) once conversion begins, a proportionate share (up to 49%) of total vessel and conversion costs (estimated to be $120 million). The third-party must make all contributions to Vulcan on or before December 28, 2006.

We will also upgrade the *Q4000* to include drilling via the addition of a modular-based drilling system for approximately $40 million, of which approximately $29.5 million had been committed at June 30, 2006.

Financing Activities. We have financed seasonal operating requirements and capital expenditures with internally generated funds, borrowings under credit facilities, sale of equity and project financings.

Senior Credit Facilities

On July 3, 2006, we entered into the Credit Agreement with Bank of America, N.A., as administrative agent and as lender, together with the other lenders party thereto, pursuant to which we borrowed $835 million in the Term Loan and may borrow Revolving Loans under a Revolving Credit Facility up to an outstanding amount of $300 million. In addition, the Revolving Credit Facility may be used for issuances of letters of credit up to an outstanding amount of $50 million.

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Convertible Senior Notes

On March 30, 2005, we issued $300 million of 3.25% Convertible Senior Notes due 2025 at 100% of the principal amount to certain qualified institutional buyers. Proceeds from the offering were used for general corporate purposes including a capital contribution of $72 million (made in March 2005) to Deepwater Gateway, L.L.C. to enable it to repay its term loan, $163.5 million related to the ERT acquisition of the Murphy properties in June 2005 and approximately $85.6 million to partially fund the Torch vessels acquired in August 2005.

MARAD Debt

The MARAD debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. We made one payment during each of the six months ended June 30, 2006 and 2005 totaling $1.8 million and $2.1 million, respectively. 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 June 30, 2006, 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.

Revolving Credit Facility

In August 2004, we entered into a four year, $150 million revolving credit facility with a syndicate of banks, with Bank of America, N.A. as administrative agent and lead arranger. We cancelled this credit facility on June 30, 2006 and replaced it with the $300 million Revolving Credit Facility that became effective on July 3, 2006. As a result, we expensed the remaining unamortized deferred financing cost of $407,000 as of June 30, 2006.

Other

Related to our $55 million cumulative convertible preferred stock, we paid $1.9 million and $1.1 million in dividends for the six months ended June 30, 2006 and 2005, respectively. The holder may redeem the value of its original and additional investment in the preferred shares to be settled in common stock at the then prevailing market price or cash at our discretion. In the event we are unable to deliver registered common shares, we could be required to redeem in cash.

In addition, in connection with the acquisition of Helix Energy Limited, on November 3, 2005, we entered into a two-year note payable to former owners totaling approximately 3.1 million British Pounds, or approximately $5.6 million ($5.8 million at June 30, 2006). The notes bear interest at a LIBOR based floating rate with payments due quarterly beginning on January 31, 2006. Principal amounts are due in November 2007.

In connection with borrowings under credit facilities and long-term debt financings, we have paid deferred financing costs totaling $1.9 million and $8.0 million in the six months ended June 30, 2006 and 2005, respectively.

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Related to the Canyon purchase in January 2002, we purchased the final one-third of the redeemable shares at the minimum purchase price of $13.53 per share ($2.4 million) in March 2005. Consideration included approximately $337,000 of contingent consideration relating to tax gross-up payments paid to the Canyon employees in accordance with the purchase agreement. This gross-up amount was recorded as goodwill in the period paid.

During the six months ended June 30, 2006 and 2005, we made payments of $1.5 million and $1.4 million, respectively, on capital leases relating to Canyon. The only other financing activity during the six months ended June 30, 2006 and 2005 involved exercises of employee stock options of $8.5 million and $6.9 million, respectively. In addition, in the first half of 2006, financing activities included $7.5 million of excess tax benefits related to exercise of options and vesting of restricted shares. Excess tax benefits related to the exercise of stock options were included in cash flow from operating activities prior to January 1, 2006.

The following table summarizes our contractual cash obligations as of June 30, 2006 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
MARAD debt	133,129	3,731	8,030	8,851	112,517
Loan notes	5,796		5,796		
Capital leases	5,361	2,585	2,776		
Acquisition of businesses[(3)]	848,700	848,700			
Investments in Independence Hub, LLC	11,700	11,700			
Drilling and development costs	41,000	41,000			
Property and equipment[(4)]	44,700	44,700			
Operating leases[(5)]	27,458	14,171	3,807	3,183	6,297
Total cash obligations	$ 1,417,844	$ 966,587	$ 20,409	$ 12,034	$ 418,814

(1) Excludes guarantee of performance related to the construction of the Independence Hub platform under Independence Hub, LLC (estimated to be immaterial at June 30, 2006) and unsecured letters of credit outstanding at June 30, 2006

totaling $6.9 million. These letters of credit primarily guarantee various contract bidding and insurance activities.

(2) Maturity 2025. Can be converted prior to stated maturity if closing sale price of Helix s common stock for at least 20 days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter exceeds 120% of the closing price on that 30th trading day (i.e. $38.56 per share).

(3) Acquisition of businesses commitment at June 30, 2006 consists of the remaining unfunded portion of the pending FDI acquisition for approximately $21.0 million (see Note 18) and the cash portion of the Remington acquisition of

$807.7 million and approximately $20.0 million of transaction costs, which were funded through a credit agreement. See Note 21 to the Condensed Consolidated Financial Statements included herein for detailed discussion of this transaction. The Credit Agreement for the Term Loan of $835 million and Revolving Credit Facility of up to $300 million were excluded from the table above as the effective date was July 3, 2006.

(4) At December 31, 2005, we had committed to purchase a certain Contracting Services vessel (*Caesar*) to be converted into a deepwater pipelay vessel. The vessel was purchased in January 2006 for $27.5 million and estimated

conversion costs are estimated to be approximately $93 million, of which approximately $15.2 million was committed at June 30, 2006. Further, we will upgrade the *Q4000* to include drilling via the addition of a modular-based drilling system for approximately $40 million, of which approximately $29.5 million had been committed at June 30, 2006.

(5) Operating leases include facility leases and vessel charter leases. Vessel charter lease commitments at June 30, 2006 were approximately $12.1 million.

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In addition, in connection with our business strategy, we regularly evaluate acquisition opportunities (including additional vessels as well as interest in offshore natural gas and oil properties). We believe internally generated cash flow, borrowings under existing credit facilities and use of project financings along with other debt and equity alternatives will provide the necessary capital to meet these obligations and achieve our planned growth. However, there can be no assurance that sufficient financing will be available for all future capital expenditures.

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Item 3. Quantitative and Qualitative Disclosure about Market Risk

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

Interest Rate Risk

Because only 1% of our outstanding debt at June 30, 2006 was based on floating rates, changes in interest would, assuming all other things equal, have a minimal impact on interest expense.

Commodity Price Risk

We have utilized derivative financial instruments with respect to a portion of 2006 and 2005 oil and gas production to achieve a more predictable cash flow by reducing our exposure to price fluctuations. We do not enter into derivative or other financial instruments for trading purposes.

As of June 30, 2006, we have the following volumes under derivative contracts related to our oil and gas producing activities:

Production Period	Instrument Type	Average Monthly Volumes	Weighted Average Price
Crude Oil:			
July 2006 December 2006	Collar	125 MBbl	$44.00 $70.48
January 2007 December 2007	Collar	50 MBbl	$40.00 $62.15
Natural Gas:			
July 2006 December 2006	Collar	600,000 MMBtu	$7.25 $13.40
January 2007 June 2007	Collar	550,000 MMBtu	$8.00 $13.69
July 2007 December 2007	Collar	233,333 MMBtu	$7.50 $10.79

We have not entered into any hedge instruments subsequent to June 30, 2006. 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 June 30, 2006, Remington had oil forward sales contracts for the period from July 2006 through June 2007. The contracts cover 50.7 MBbl per month at a weighted average price of $70.48. In addition, Remington had natural gas forward sales contracts for the period from July 2006 through June 2007. The contracts cover 733,000 MMbtu per month at a weighted average price of $9.31. These hedges do not qualify for hedge accounting.

Foreign Currency Exchange Rates

Because we operate in various oil and gas exploration and production regions in the world, we conduct a portion of our business in currencies other than the U.S. dollar (primarily with respect to Well Ops (U.K.) Limited and Helix Energy Limited). The functional currency for Well Ops (U.K.) Limited and Helix Energy Limited is the applicable local currency (British Pound). Although the revenues are denominated in the local currency, the effects of foreign currency fluctuations are partly mitigated because local expenses of such foreign operations also generally are denominated in the same currency. The impact of exchange rate fluctuations during each of the three and six months ended June 30, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

Assets and liabilities of Wells Ops (U.K.) Limited and Helix Energy Limited are translated using the exchange rates in effect at the balance sheet date, resulting in translation adjustments that are reflected in accumulated other comprehensive income in the shareholders equity section of our balance sheet. Approximately 10% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar at June 30, 2006. We recorded unrealized gains of $7.8 million and $9.0 million to our equity account for the three and six months ended June 30, 2006, respectively, and $5.0 million and $6.7 million of unrealized losses to our equity account for the three and six months ended June 30, 2005, respectively. Deferred taxes have not been provided on foreign currency translation adjustments since we consider our undistributed earnings (when applicable) of our non-U.S. subsidiaries to be permanently reinvested.

Canyon Offshore, our ROV subsidiary, has operations in the United Kingdom and Southeast Asia sectors. Canyon conducts the majority of its operations in these regions in U.S. dollars which it considers the functional currency. When currencies other than the U.S. dollar are to be paid or received, the resulting transaction gain or loss is recognized in the statements of operations. These amounts for the three and six months ended June 30, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

Item 4. Controls and Procedures

(a) *Evaluation of disclosure controls and procedures*. Our management, with the participation of our principal executive officer (CEO) and principal financial officer (CFO), 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 June 30, 2006. Based on this evaluation, the CEO and CFO have concluded that the our disclosure controls and procedures were effective as of the end of the fiscal quarter ended June 30, 2006 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting that occurred during the fiscal quarter ended June 30, 2006 that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

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Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

In addition to the risk factors disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005, we add the following risk factors as a result of recent events:

We may face difficulties in achieving the expected benefits of the acquisition of Remington Oil and Gas Corporation.

Management may not be able to realize the operating efficiencies, synergies, cost savings or other benefits management expected from the merger. In addition, the costs we incur in implementing synergies, including our ability to amend, renegotiate or terminate prior contractual commitments of Helix and Remington, may be greater than expected. We also may suffer a loss of employees, customers or suppliers, a loss of revenues, or an increase in operating or other costs or other difficulties relating to the merger. Our actual financial position and results of operations may differ significantly and adversely from management s expectations.

We have higher levels of indebtedness following the merger than we had before the merger.

Following the merger, we have higher levels of debt and interest expense than Helix and Remington, together, had immediately prior to the merger. As of July 3, 2006, after giving effect to the merger and the related financings, the combined company and its subsidiaries have approximately $1.3 billion of indebtedness outstanding. The significant level of combined indebtedness may have an effect on the combined company s future operations, including:

- limiting our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, acquisitions, investments, debt service requirements and other general corporate requirements;

- increasing our vulnerability to general economic downturns, competition and industry conditions, which could place us at a competitive disadvantage compared to our competitors that are less leveraged;

- increasing our exposure to rising interest rates because a portion of our borrowings are at variable interest rates;

- reducing the availability of our cash flow to fund our working capital requirements, capital expenditures, acquisitions, investments and other general corporate requirements because we will be required to use a substantial portion of our cash flow to service debt obligations; and

- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

If the initial public offering of the common stock of CDI is completed, we may not have the same access to such equipment as we have historically.

We plan to continue to control the business of CDI in the foreseeable future and retain access to the services and equipment owned by CDI. However, once the initial public offering of CDI s common stock is completed, we may not have the same access to those services and equipment as we have historically. If our ownership in CDI decreases over time, our ability to control the business of CDI and retain access to the services and equipment owned by CDI could be further diminished.

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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 (in millions)
April 1 to April 30, 2006		$		$ N/A
May 1 to May 31, 2006				N/A
June 1 to June 30, 2006 (1)	1,932	39.39		N/A
	1,932	$ 39.39		$ N/A

(1) 1,932 shares subject to restricted share awards were withheld to satisfy tax obligations arising upon the vesting of restricted shares.

Item 4. Submission of Matters to a Vote of Security Holders

The Annual Meeting of the Shareholders of the Company was held on May 8, 2006, in Houston, Texas, for the purpose of electing two Class II directors for three year terms ending in 2009. Proxies for the meeting were solicited pursuant to Section 14(a) of the Securities Exchange Act of 1934, and there was no solicitation in opposition to management s solicitation.

Proposal 1: Each of the Class II directors nominated by the Board of Directors and listed in the proxy statement was elected with votes as follows:

Nominee	Shares For	Shares Withheld
T. William Porter, III	62,265,148	4,665,589
William L. Transier	63,768,471	3,162,266

The term of office of each of the following directors continued after the meeting:

Gordon F. Ahalt

Bernard J. Duroc-Danner

Martin Ferron
Owen Kratz
John V. Lovoi
Anthony Tripodo

Item 6. Exhibits

15.1 Independent Registered Public Accounting Firm s Acknowledgement Letter(1)

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

31.2 Certification Pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934 by A. Wade Pursell, Chief Financial

32.1 Section 1350 Certification by Owen Kratz, Chief Executive Officer(2)

32.2 Section 1350 Certification by A. Wade Pursell, Chief Financial Officer(2)

99.1 Report of Independent Registered Public Accounting Firm(1)

(1) Filed herewith

(2) Furnished herewith

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SIGNATURES

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

HELIX ENERGY SOLUTIONS GROUP, INC.
(Registrant)

Date: August 3, 2006 By: **/s/ Owen Kratz**

Owen Kratz
Chairman and Chief Executive Officer

Date: August 3, 2006 By: **/s/ A. Wade Pursell**

A. Wade Pursell
Senior Vice President and
Chief Financial Officer

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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

32.1 Section 1350 Certification by Owen Kratz, Chief Executive Officer[2]

32.2 Section 1350 Certification by A. Wade Pursell, Chief Financial Officer[2]

99.1 Report of Independent Registered Public Accounting Firm[1]

(1) Filed herewith

(2) Furnished herewith

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