HELIX ENERGY SOLUTIONS GROUP INC
Form 10-Q
November 07, 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 September 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 November 3, 2006, 93,356,999 shares of common stock were outstanding.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

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

	September 30, 2006 (Unaudited)	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 127,785	$ 91,080
Accounts receivable		
Trade, net of allowance for uncollectible accounts of $781 and $585	247,285	197,046
Unbilled revenue	52,695	31,012
Other current assets	87,143	52,915
Total current assets	514,908	372,053
Property and equipment	2,494,844	1,259,014
Less Accumulated depreciation	(448,350)	(342,652)
	2,046,494	916,362
Other assets:		
Equity investments	210,457	179,844
Goodwill, net	805,706	101,731
Other assets, net	132,382	90,874
	$ 3,709,947	$ 1,660,864
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 208,398	$ 99,445
Accrued liabilities	177,192	145,752
Current maturities of long-term debt	14,727	6,468
Total current liabilities	400,317	251,665
Long-term debt	1,262,098	440,703
Deferred income taxes	441,359	167,295
Decommissioning liabilities	138,713	106,317
Other long-term liabilities	4,582	10,584
Total liabilities	2,247,069	976,564
Convertible preferred stock	55,000	55,000

Commitments and contingencies		
Shareholders equity:		
Common stock, no par, 240,000 shares authorized, 119,486 and 104,898 shares issued	802,046	233,537
Retained earnings	590,305	408,748
Treasury stock, 27,212 and 27,204 shares, at cost	(4,017)	(3,741)
Unearned compensation		(7,515)
Accumulated other comprehensive income (loss)	19,544	(1,729)
Total shareholders equity	1,407,878	629,300
	$ 3,709,947	$ 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 September 30, 2006	Three Months Ended September 30, 2005
Net revenues:		
Contracting services	$ 229,392	$ 133,875
Oil and gas	145,032	75,463
	374,424	209,338
Cost of sales:		
Contracting services	143,517	91,824
Oil and gas	100,437	34,586
	243,954	126,410
Gross profit	130,470	82,928
Gain on sale of assets	2,287	329
Selling and administrative expenses	30,309	15,892
Income from operations	102,448	67,365
Equity in earnings of investments	1,897	3,721
Net interest expense and other	15,103	2,766
Income before income taxes	89,242	68,320
Provision for income taxes	31,409	25,099
Net income	57,833	43,221
Preferred stock dividends	804	550
Net income applicable to common shareholders	$ 57,029	$ 42,671
Earnings per common share:		
Basic	$ 0.62	$ 0.55
Diluted	$ 0.60	$ 0.53
Weighted average common shares outstanding:		
Basic	91,531	77,526

Diluted	96,918	82,160

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

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

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Net revenues:		
Contracting services	$ 664,630	$ 329,005
Oil and gas	306,455	206,439
	971,085	535,444
Cost of sales:		
Contracting services	408,919	249,206
Oil and gas	197,738	99,018
	606,657	348,224
Gross profit	364,428	187,220
Gain on sale of assets	2,570	1,254
Selling and administrative expenses	78,751	41,588
Income from operations	288,247	146,886
Equity in earnings of investments	12,653	8,158
Net interest expense and other	20,543	4,868
Income before income taxes	280,357	150,176
Provision for income taxes	96,387	54,418
Net income	183,970	95,758
Preferred stock dividends	2,413	1,650
Net income applicable to common shareholders	$ 181,557	$ 94,108
Earnings per common share:		
Basic	$ 2.20	$ 1.22
Diluted	$ 2.09	$ 1.17
Weighted average common shares outstanding:		
Basic	82,706	77,372

Diluted	88,209	81,962

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)

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
Cash flows from operating activities:		
Net income	$ 183,970	$ 95,758
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	131,451	83,925
Asset impairment charge		790
Dry hole expense	37,615	
Equity in earnings of investments, net of distributions	(4,835)	(672)
Amortization of deferred financing costs	1,582	839
Stock compensation expense	6,250	733
Deferred income taxes	64,561	49,993
Gain on sale of assets	(2,570)	(1,254)
Excess tax benefit from stock-based compensation	(7,842)	
Changes in operating assets and liabilities:		
Accounts receivable, net	(442)	(35,349)
Other current assets	(19,609)	(22,862)
Accounts payable and accrued liabilities	(25,105)	51,654
Other noncurrent, net	(23,440)	(40,560)
Net cash provided by operating activities	341,586	182,995
Cash flows from investing activities:		
Capital expenditures	(253,386)	(319,139)
Acquisition of businesses, net of cash acquired	(872,707)	
Investments in production facilities & OTSL	(23,092)	(102,182)
Affiliate loan to OTSL		(1,500)
Distributions from equity investments, net		8,614
Increase in restricted cash	(21,404)	(1,779)
Proceeds from sales of property	31,827	4,212
Net cash used in investing activities	(1,138,762)	(411,774)
Cash flows from financing activities:		
Borrowings under Senior Credit Facilities	835,000	
Borrowings on Convertible Senior Notes		300,000
Borrowings under MARAD loan facility		2,836
Repayment of MARAD borrowings	(3,641)	(4,321)
Deferred financing costs	(11,143)	(10,965)
Capital lease payments	(2,184)	(2,123)
Preferred stock dividends paid	(2,668)	(1,650)
Redemption of stock in subsidiary		(2,438)

Repurchase of common stock	(266)	
Excess tax benefit from stock-based compensation	7,842	
Exercise of stock options, net	8,775	7,246
Net cash provided by financing activities	831,715	288,585
Effect of exchange rate changes on cash and cash equivalents	2,166	(451)
Net increase in cash and cash equivalents	36,705	59,355
Cash and cash equivalents:		
Balance, beginning of year	91,080	91,142
Balance, end of period	$ 127,785	$ 150,497

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

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

Note 1 Basis of Presentation

The accompanying condensed consolidated financial statements include the accounts of Helix Energy Solutions Group, Inc. (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. Our 2005 Annual Report on Form 10-K contains a detailed description of our critical accounting policies. In addition, due to the acquisition of Remington Oil and Gas Corporation (Remington) on July 1, 2006, we have expanded our critical accounting policies related to our Oil and Gas segment. See a discussion of these critical accounting policies in Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates included herein.

Management has reflected all adjustments (which were normal recurring adjustments unless otherwise disclosed herein) that it believes are necessary for a fair presentation of the condensed consolidated balance sheets, results of operations and cash flows, as applicable. Operating results for the period ended September 30, 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 and reporting dry hole cost as a component of our exploration costs instead of as a component of depreciation, depletion and amortization costs on the statement of cash flows due to the significance of our oil and gas exploration activities as a result of our recent acquisition (see Note 3).

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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 September 30, 2006 and December 31, 2005, we had $48.4 million and $27.0 million, respectively, of restricted cash included in other assets, net. As of September 30, 2006 and December 31, 2005, $33.4 million and $27.0 million, respectively, were related to Energy Resource Technology, Inc. (merged into and now known as Energy Resources Technology GOM, Inc.) (ERT), a wholly owned subsidiary of the Company, escrow funds for decommissioning liabilities associated with the South Marsh Island 130 (SMI 130) acquisition in 2002. Under the purchase agreement for those acquisitions, ERT was 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 has fully escrowed the requirement as of September 30, 2006. ERT may use the restricted cash for decommissioning the related field. Further, $15.0 million of restricted cash at September 30, 2006 was temporarily held in escrow as required by the senior credit facility we entered into in July 2006 (see Note 8 below).

The following table provides supplemental cash flow information for the three and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Interest paid (net of capitalized interest)	$ 1,312	$2,484	$ 6,385	$5,847
Income taxes paid	$15,380	$ 780	$56,794	$2,013

Non-cash investing activities for the nine months ended September 30, 2006 included $71.5 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 Acquisition of Remington Oil and Gas Corporation

On July 1, 2006, we acquired 100% of Remington, an independent oil and gas exploration and production company headquartered in Dallas, Texas, with operations concentrated in the onshore and offshore regions of the Gulf Coast, for approximately $1.4 billion in cash and stock and the assumption of $345.5 million of liabilities. The merger consideration was 0.436 of a share of our common stock and $27.00 in cash for each share of Remington common stock. On July 1, 2006, we issued 13,032,528 shares of our common stock to Remington stockholders and funded the cash portion of the Remington acquisition (approximately $806.8 million) and transaction costs (approximately $18.3 million) through a credit agreement (see Note 8 below).

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The Remington acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values, with excess being recorded in goodwill. The following table summarizes the estimated preliminary fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Current assets	$ 156,409
Property and equipment	861,147
Goodwill	699,760
Other intangible assets[1]	6,800
Total assets acquired	$ 1,724,116
Current liabilities	$ 120,778
Deferred income taxes	205,952
Decommissioning liabilities	18,740
Total liabilities assumed	$ 345,470
Net assets acquired	$ 1,378,646

(1) The intangible asset is related to a favorable drilling rig contract and several non-compete agreements between the Company and certain members of senior management. The preliminary fair value of the drilling rig contract was $5.0 million and the amount will be reclassified into property and equipment if drilling of certain exploratory wells is

successful. If drilling is unsuccessful, the intangible asset will be expensed in the period drilling is determined to be unsuccessful. The preliminary fair value of the non-compete agreements was $1.8 million, which will be amortized over the term of the agreements (three years) on a straight-line basis.

The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management s review of the final valuations. The primary areas of the purchase price allocation which are not yet finalized relate to valuation of certain proved and unproved oil and gas properties and identification and valuation of potential intangible assets. The final valuation is expected to be completed no later than one year from the acquisition date.

The results of the acquisition are included in the accompanying statements of operations since the date of purchase in our Oil and Gas segment (formerly known as our Oil and Gas Production segment). Pro forma combined operating results of the Company and the Remington acquisition for the three and nine months ended September 30, 2006 and 2005 were presented as if the acquisition had been completed as of January 1, 2006 and January 1, 2005, respectively. The pro forma combined results were as follows (in thousands, except per share data):

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2006	**2005**	**2006**	**2005**
Net revenues	$374,424	$280,838	$1,113,700	$742,162
Income before income taxes(1)	89,242	81,188	267,256	173,096
Net income	57,833	51,492	174,929	110,376
Net income applicable to common shareholders	57,029	50,942	172,515	108,726
Earnings per common share:				
Basic	$ 0.62	$ 0.56	$ 1.89	$ 1.20
Diluted	$ 0.60	$ 0.54	$ 1.81	$ 1.16

(1) Includes approximately $11.5 million of severance and incentive compensation expense, and

approximately $20.6 million of non-cash stock compensation expense for vesting of stock options and restricted shares incurred by Remington in June 30, 2006.

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Note 4 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.

At September 30, 2006, we had capitalized approximately $19.1 million of exploratory drilling costs associated with ongoing exploration and/or appraisal activities. Such capitalized costs may be charged against earnings in future periods if management determines that commercial quantities of hydrocarbons have not been discovered or that future appraisal drilling or development activities are not likely to occur. The following table provides a detail of our capitalized exploratory project costs at September 30, 2006 (in thousands):

Huey(1)	$ 10,855
Castleton (part of *Gunnison*)(1)	8,129
Other	75
Total	$ 19,059

(1) Suspended as of September 30, 2006

The following table reflects net changes in suspended exploratory well costs during the first nine months of 2006 (in thousands):

Beginning balance at January 1, 2006	$ 12,349
Additions pending the determination of proved reserves	44,250
Reclassifications to proved properties	
Charged to dry hole expense	(37,615)
	$ 18,984

As of September 30, 2006, all of these exploratory well costs have been capitalized for a period of one year or less.

Further, the following table details the components of exploration expense for the three and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Delay rental	$ 509	$ 371	$ 799	$ 623
Geological and geophysical costs	2,142	557	2,881	5,327
Dry hole expense	16,869		37,615	
Total exploration expense	$ 19,520	$ 928	$ 41,295	$ 5,950

In addition, in the three and nine months ended September 30, 2006, we expensed inspection and repair costs related to damages sustained by Hurricanes *Katrina* and *Rita* for our oil and gas properties totaling approximately $5.8 million and $14.9 million, respectively, partially offset by $1.6 million and $4.3 million of insurance recoveries recognized in the three and nine months ended September 30, 2006, respectively. At June 30, 2006, Remington had approximately $18.3 million of insurance receivables, which were all collected in the third quarter of 2006.

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 $21.7 million was charged to earnings during the nine months ended September 30, 2006. We continue to evaluate various options with the operator for recovering the potential reserves. Further, in the third quarter of 2006, we expensed approximately $15.9 million of exploratory drilling costs related to two deep shelf properties (acquired in the Remington acquisition which were in process prior to July 1, 2006) in which we determined commercial quantities of hydrocarbons were not discovered.

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 would not pursue its 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. We recorded a gain of $2.2 million in the third quarter of 2006 related to this sale.

Note 5 Other 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 purchase from Acergy. Under the terms of the clearance, we will divest one diving support vessel and have previously disposed of one diving support vessel and a portable saturation diving system from the combined asset package acquired through this transaction and the asset purchases in August of 2005 from Torch Offshore, Inc. (Torch). These assets were included in assets held for sale totaling $100,000 and $7.8 million as of September 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 included: 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.

The Acergy acquisition was accounted for as a business combination 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. 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 to the historical results of the Company.

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. The balance of the promissory note as of September 30, 2006 was $1.5 million. We expect to collect the remaining balance. 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 September 30, 2006, was approximately $17.8 million. In addition, if the lessee exercises the purchase option 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. If the lessee elects not to exercise its option to purchase the remaining 50% interest in the vessel, minimum future rentals to be received on this lease are $68.0 million through January 2016.

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 during the second half of 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 the proportionate share of the cost of the vessel plus the actual cost of conversion (conversion cost is estimated to be $90 million). The third party must make all contributions to Vulcan on or before March 31, 2007.

To expand our international operations, in July 2006, we acquired the business of Singapore-based Fraser Diving International Ltd (FDI) for an aggregate purchase price of approximately $29.8 million, subject to post-closing adjustments, and the assumption of $1.8 million of liabilities. FDI owns six portable saturation diving systems and 15 surface diving systems that operate primarily in Southeast Asia, the Middle East, Australia and the Mediterranean. As a part of the 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. The acquisition was accounted for as a business combination with the acquisition price allocated to the assets acquired and liabilities assumed based upon their estimated fair values. The following table summarizes the estimated preliminary fair values of the assets acquired and liabilities assumed at the date of acquisition (in thousands):

Portable saturation diving systems and surface diving systems	$ 22,813
Diving support equipment, support facilities and other equipment	4,077
Cash and cash equivalents	2,332
Accounts receivable	1,817
Prepaid expenses and deposits	542
Total assets acquired	$ 31,581
Accounts payable and accrued liabilities	$ 1,763
Net assets acquired	$ 29,818

The allocation of the purchase price was based upon preliminary valuations. Estimates and assumptions are subject to change upon the receipt and management s review of the final valuations. The primary areas of the purchase price allocation that are not yet finalized relate to post closing purchase price adjustments and identification and valuation of potential intangible assets. The final valuation of net assets is expected to be completed no later than one year from the acquisition date. The results of FDI are included in the accompanying condensed consolidated statements of operations since the date of purchase in our Shelf Contracting segment. Pro forma combined operating results for the three and nine months ended September 30, 2006 and 2005 (adjusted to reflect the results of operations of FDI prior to its acquisition) are not provided because the pre-acquisition results related to FDI were not material to the historical results of the Company.

Note 6 Details of Certain Accounts (in thousands)

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

	September 30, 2006	December 31, 2005
Other receivables	$ 1,790	$ 1,386
Prepaids	38,208	13,182
Income tax receivable	25,642	
Spare parts inventory	3,441	3,628
Current deferred tax assets	2,621	8,861
Gas imbalance	4,849	3,888
Current notes receivable	3,008	1,500
Assets held for sale	100	7,936
Other	7,484	12,534

	$	87,143	$	52,915

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

	September 30, 2006	December 31, 2005
Restricted cash	$ 48,414	$ 27,010
Deposits	801	4,594
Deferred drydock expenses, net	24,619	18,285
Deferred financing costs	28,393	18,714
Intangible assets with definite lives	21,079	14,707
Intangible asset with indefinite life	6,613	6,074
Other	2,463	1,490
	$ 132,382	$ 90,874

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

	September 30, 2006	December 31, 2005
Accrued payroll and related benefits	$ 30,040	$ 27,982
Royalties payable	68,468	46,555
Current decommissioning liability	17,592	15,035
Hedging liability		8,814
Income taxes payable		7,288
Deposits		10,000
Accrued interest	16,275	2,610
Other	44,817	27,468
	$ 177,192	$ 145,752

Note 7 Equity Investments

As of September 30, 2006, we have the following investments that are accounted for under the equity method of accounting:

Deepwater Gateway, L.L.C. In June 2002, we, along with Enterprise Products Partners L.P. (Enterprise), formed Deepwater Gateway, L.L.C. (a 50/50 venture) to design, construct, install, own and operate a tension leg platform (TLP) production hub primarily for Anadarko Petroleum Corporation s *Marco Polo* field discovery in the Deepwater Gulf of Mexico. Our investment in Deepwater Gateway, L.L.C. totaled $122.5 million and $117.2 million as of September 30, 2006 and December 31, 2005, respectively.

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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 $76.8 million and $50.8 million as of September 30, 2006 and December 31, 2005, respectively, and our total investment is expected to be approximately $84 million. We expect to complete our investment by the end of 2006. 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 September 30, 2006 based upon the remote possibility of payments being made under the performance guarantee.

OTSL. In July 2005, we acquired a 40% minority ownership interest in OTSL in exchange for our DP DSV, *Witch Queen*. Our investment in OTSL totaled $10.8 million and $11.5 million at September 30, 2006 and December 31, 2005, respectively. 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. We have agreed to extend the lump sum principal payment due date and have 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 $7.7 million in 2006. The charter ended in March 2006.

Under the equity method of accounting, an impairment loss would be recorded whenever a decline in value of an equity investment below its carrying amount was determined to be other than temporary. In judging other than temporary, we would consider the length of time and extent to which the fair value of the investment has been less than the carrying amount of the equity investment, the near-term and longer-term operating and financial prospects of the equity company and our longer-term intent of retaining the investment in the entity. We have reported a net loss of $587,000 for the nine months ended September 30, 2006 related to our investment in OTSL. This net loss is an impairment indicator. However, we believe the current operating trend is temporary and have determined that the fair value of this investment, based on an estimate of its discounted cash flows, exceeds its carrying amount. As a result, there was no impairment at September 30, 2006.

Note 8 Long-Term Debt

Senior Credit Facilities

On July 3, 2006, we entered into a Credit Agreement (the Credit Agreement) with Bank of America, N.A., as administrative agent and as lender, together with the other lenders (collectively, the Lenders). Under the Credit Agreement, we borrowed $835 million in a term loan (the Term Loan) and may borrow 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.

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 LIBOR. The Term Loan or portions thereof bearing interest at LIBOR will bear interest at a per annum rate equal to the LIBOR selected by us plus 2.00%. Our current election is to bear interest based on LIBOR. Our interest rate for the three months ended September 30, 2006 was approximately 7.5%.

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

The Revolving Loans or portions thereof bearing interest at LIBOR will bear interest based on one, three or six month LIBOR at our election plus a margin ranging from 1.00% to 2.25%. Margins on the Revolving Loans will fluctuate in relation to the consolidated leverage ratio 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. We made our first quarterly principal payment on October 2, 2006. Quarterly principal payments 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 issuance or incurrence 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 the Company s 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. 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. As of September 30, 2006, we were in compliance with these covenants.

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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 as part of the Remington acquisition. The liens on the assets and properties of Cal Dive International, Inc. (CDI) and its subsidiaries securing the Loans will automatically be released, and their obligations under the Loan Documents will automatically be released, upon an initial public offering of a minority interest in CDI common stock as described in Note 20 below. Dispositions of the equity in 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 an initial public offering) are permitted transfers under the Credit Agreement. Under the terms of the Credit Agreement, mortgages on CDI s vessels and properties were not required, provided that the initial public offering was consummated by October 31, 2006. As the initial public offering was not completed as of October 31, 2006, we will be required to provide these mortgages no later than January 31, 2007, unless an initial public offering is completed prior to that date.

In July 2006, ERT sold its interest in Telemark and surrounding fields for $15 million in cash (see Note 4 above). The sale of this asset constituted a disposition under the Credit Agreement and required either prepayment of the Term Loan by the amount of the sale or the escrow of proceeds until the amount could be invested in qualified replacement collateral. We elected to transfer the $15 million cash received into an escrow account held by Bank of America for use in the purchase of or investment in qualified replacement assets. The funds held in escrow will be released upon submission of qualified capital expenditures to Bank of America. The restricted cash is reported in other assets, net as of September 30, 2006.

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 third quarter of 2006, no conversion triggers were met.

Approximately 1.2 million shares and 1.3 million shares underlying the Convertible Senior Notes were included in the calculation of diluted earnings per share for the three and nine months ended September 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 September 30, 2006 and December 31, 2005, we estimated the fair value of our $300 million (carrying value) fixed-rate debt to be $400.7 million and $433.7 million, respectively, based upon quoted market prices.

MARAD Debt

At September 30, 2006, $131.3 million was outstanding on our long-term financing for construction of the *Q4000.* This U.S. Government guaranteed financing is pursuant to Title XI of the Merchant Marine Act of 1936 which is administered by the Maritime Administration (MARAD Debt). The MARAD Debt is payable in equal semi-annual installments which began in August 2002 and matures 25 years from such date. The MARAD Debt is collateralized by the *Q4000,* with us guaranteeing 50% of the debt, and initially bore interest at a floating rate which approximated AAA Commercial Paper yields plus 20 basis points. As provided for in the MARAD Debt agreements, in September 2005, we fixed the interest rate on the debt through the issuance of a 4.93% fixed-rate note with the same maturity date (February 2027). In accordance with the MARAD Debt agreements, we are required to comply with certain covenants and restrictions, including the maintenance of minimum net worth, working capital and debt-to-equity requirements. As of September 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.

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 $5.9 million at September 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.

In connection with borrowings under our long-term debt financings described above, we paid deferred financing cost of $11.1 million and $11.0 million during the nine months ended September 30, 2006 and 2005, respectively. Deferred financing costs of $28.4 million and $18.7 million are included in other assets, net as of September 30, 2006 and December 31, 2005, respectively, and are being amortized over the life of the respective agreement.

Scheduled maturities of long-term debt and capital lease obligations outstanding as of September 30, 2006 were as follows (in thousands):

	MARAD Debt	Convertible Senior Notes	Term Loan	Revolving Loan	Loan Notes	Capital Leases	Total
Less than one year	$ 3,823	$	$ 8,400	$	$	$ 2,504	$ 14,727
One to two years	4,014		8,400		5,871	2,163	20,448
Two to Three years	4,214		8,400				12,614
Three to four years	4,424		8,400				12,824
Four to five years	4,645		8,400				13,045
Over five years	110,167	300,000	793,000				1,203,167
Long-term debt	131,287	300,000	835,000		5,871	4,667	1,276,825
Current maturities	(3,823)		(8,400)			(2,504)	(14,727)
Long-term debt, less current maturities	$ 127,464	$ 300,000	$ 826,600	$	$ 5,871	$ 2,163	$ 1,262,098

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We had unsecured letters of credit outstanding at September 30, 2006 totaling approximately $7.8 million. These letters of credit primarily guarantee various contract bidding and insurance activities. The following table details our interest expense and capitalized interest for the three and nine months ended September 30, 2006 and 2005 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Interest expense	$ 20,225	$ 4,275	$ 29,856	$ 9,826
Interest income	(2,474)	(1,509)	(3,971)	(4,520)
Capitalized interest	(2,604)	(526)	(5,014)	(1,113)
Interest expense, net	$ 15,147	$ 2,240	$ 20,871	$ 4,193

Note 9 Income Taxes

The effective tax rate of 35% and 34% for the three and nine months ended September 30, 2006, respectively, was lower than the effective rate of 37% and 36% for the same periods in 2005, respectively. The lower tax rate was due to our ability to realize foreign tax credits and oil and gas percentage depletion as a result of 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 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 and variable interest rate exposure. All derivatives are reflected in our balance sheet at fair value, unless otherwise noted.

Commodity Hedges

During 2005 and the first nine months 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 asset (liability) of $3.5 million and $(13.4) million as of September 30, 2006 and December 31, 2005, respectively. We recorded unrealized gains of approximately $8.6 million and $11.0 million, net of tax expense of $4.6 million and $5.9 million, during the three and nine months ended September 30, 2006, respectively, in accumulated other comprehensive income (loss), a component of shareholders equity, as these hedges were highly effective. For the three and nine months ended September 30, 2005, we recorded $11.7 million and $18.4 million, respectively, of unrealized losses, net of tax benefit of $6.3 million and $9.9 million, respectively. During the three and nine months ended September 30, 2006, we reclassified approximately $614,000 and $6.9 million of gains, respectively, from other comprehensive income to net revenues upon the sale of the related oil and gas production. For the three and nine months ended September 30, 2005, we reclassified approximately $3.2 million and $6.1 million, respectively, of losses from other comprehensive income to net revenues.

During the third quarter of 2005, hedge ineffectiveness related to cash flow hedge was a loss of $1.8 million, net of tax benefit of $951,000. The amount was recorded in earnings as a reduction in net revenues. Hedge ineffectiveness resulted from ERT s inability to deliver contractual oil and gas production in fourth quarter 2005 due primarily to the effects of Hurricanes *Katrina* and *Rita*. No hedge ineffectiveness was recorded during the three and nine months ended September 30, 2006.

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As of September 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:			
October 2006 December 2006	Collar	125 MBbl	$ 44.00 $70.48
January 2007 December 2007	Collar	50 MBbl	$ 40.00 $62.15
Natural Gas:			
October 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	333,333 MMBtu	$ 7.50 $11.23

We have not entered into any hedge instruments subsequent to September 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 September 30, 2006, we had oil forward sales contracts for the period from October 2006 through June 2007. The contracts cover an average of 35.3 MBbl per month at a weighted average price of $70.63. In addition, we had natural gas forward sales contracts for the period from October 2006 through June 2007. The contracts cover an average of 567,083 MMbtu per month at a weighted average price of $9.26. Hedge accounting does not apply to these contracts.

Interest Rate Hedge

As the rates for our Term Loan are subject to market influences and will vary over the term of the agreement, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payment for our Term Loan effective October 3, 2006. These interest rate swaps qualify for hedge accounting. See Note 8 above for a detailed discussion of our Term Loan.

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 $1.3 million and $10.3 million for the three and nine months ended September 30, 2006, respectively, is included in accumulated other comprehensive income (loss), a component of shareholders equity. For the three and nine months ended September 30, 2005, we recorded $1.3 million and $8.0 million, respectively, of unrealized losses in accumulated other comprehensive income related 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 nine months ended September 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 nine months ended September 30, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

In addition, FDI has operations in the Southeast Asia sector and conducts the majority of its operations in this region 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 months ended September 30, 2006 were not material to our results of operations or cash flows.

Note 12 Comprehensive Income

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Net income	$ 57,833	$ 43,221	$ 183,970	$ 95,758
Foreign currency translation gain (loss)	1,273	(1,347)	10,279	(8,024)
Unrealized gain (loss) on commodity hedges, net	8,552	(11,705)	10,994	(18,441)
Total comprehensive income	$ 67,658	$ 30,169	$ 205,243	$ 69,293

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

	September 30, 2006	December 31, 2005
Cumulative foreign currency translation adjustment	$ 17,258	$ 6,979
Unrealized gain (loss) on commodity hedges, net	2,286	(8,708)
Accumulated other comprehensive income (loss)	$ 19,544	$ (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 September 30, 2006		Three Months Ended September 30, 2005	
	Income	Shares	Income	Shares
Earnings applicable per common share Basic	$ 57,029	91,531	$ 42,671	77,526
Effect of dilutive securities:				
Stock options		386		770
Restricted shares		150		234
Employee stock purchase plan		4		
Convertible Senior Notes		1,217		
Convertible preferred stock	804	3,630	550	3,630
Earnings applicable per common share Diluted	$ 57,833	96,918	$ 43,221	82,160

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	Nine Months Ended September 30, 2006		Nine Months Ended September 30, 2005	
	Income	Shares	Income	Shares
Earnings applicable per common share Basic	$ 181,557	82,706	$ 94,108	77,372
Effect of dilutive securities:				
Stock options		445		756
Restricted shares		132		204
Employee stock purchase plan		12		
Convertible Senior Notes		1,284		
Convertible preferred stock	2,413	3,630	1,650	3,630
Earnings applicable per common share Diluted	$ 183,970	88,209	$ 95,758	81,962

There were no antidilutive stock options in the three and nine months ended September 30, 2006 and 2005, respectively. Net income for the diluted earnings per share calculation for the three and nine months ended September 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 as 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.

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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 nine months of 2006 or 2005.

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 nine months ended September 30, 2005 (in thousands, except per share amounts):

		Three Months Ended September 30, 2005		**Nine Months Ended September 30, 2005**
Net income applicable to common shareholders:				
As Reported	$	42,671	$	94,108
Add back: Stock-based compensation cost included in reported net income, net of taxes		218		476
Deduct: Total stock-based compensation cost determined under the fair value method, net of tax		(669)		(1,648)
Pro Forma	$	42,220	$	92,936
Earnings per common share:				
Basic:				
As reported	$	0.55	$	1.22
Pro forma	$	0.55	$	1.20
Diluted:				
As reported	$	0.53	$	1.17
Pro forma	$	0.52	$	1.16

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.

Stock Options

The options outstanding at September 30, 2006, have exercise prices as follows: 163,000 shares at $8.57; 67,510 shares at $9.32; 110,680 shares at $10.92; 73,000 shares at $10.94; 64,800 shares at $11.00; 181,280 shares at $12.18; 70,400 shares at $13.91; and 165,400 shares ranging from $8.14 to $12.00, and a weighted average remaining contractual life of 5.99 years.

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Options outstanding are as follows:

	September 30, 2006		September 30, 2005	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at beginning of year	1,717,904	$ 10.91	2,599,894	$ 10.65
Granted		$		$
Exercised	(779,394)	$ 11.26	(704,470)	$ 10.29
Terminated	(42,440)	$ 10.96	(23,920)	$ 10.82
Options outstanding at September 30,	896,070	$ 10.83	1,871,504	$ 10.81
Options exercisable at September 30,	528,318	$ 10.28	1,106,319	$ 10.81

For the three and nine months ended September 30, 2006, $356,000 and $1.1 million was recognized as compensation expense related to stock options. No expense related to stock options was recognized in 2005 under the intrinsic value. Total compensation cost related to nonvested options not yet recognized at September 30, 2006 was approximately $2.1 million. The weighted average vesting period related to nonvested stock options at September 30, 2006 was approximately two years.

Restricted Shares

We grant restricted shares to members of our board of directors, key executives and selected management employees. Compensation cost for each award is the product of market value of each share and the number of shares granted. The following table summarizes information about our restricted shares during the nine months ended September 30, 2006 and 2005:

	September 30, 2006		September 30, 2005	
	Shares	Fair Value(1)	Shares	Fair Value(1)
Restricted shares outstanding at beginning of year	384,902	$ 25.59		$
Granted	426,721	$ 37.83	318,606	$ 24.09
Vested	(48,708)	$ 21.76		$
Forfeited	(35,355)	$ 29.98	(1,268)	$ 19.56
Balance at September 30,	727,560	$ 32.82	317,338	$ 24.11

(1) Represents the average grant date market value, which is based on the quoted market price of the common stock on the business day prior to the

date of grant.

For the nine months ended September 30, 2005, the amounts granted were recorded as unearned compensation, a component of shareholders equity and charged to expense over the respective vesting periods on a straight-line basis. Amortization of unearned compensation totaled $335,000 and $733,000 for the three and nine months ended September 30, 2005, respectively. 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. For the three and nine months ended September 30, 2006, $1.6 million and $4.1 million, respectively, was recognized as compensation expense related to restricted shares. Total compensation cost related to nonvested restricted stock awards not yet recognized at September 30, 2006 was approximately $19.5 million. The weighted average vesting period related to nonvested restricted stock awards at September 30, 2006 was approximately four years.

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Employee Stock Purchase Plan

Effective May 12, 1998, we adopted a qualified, non-compensatory ESPP, which allows employees to acquire shares of common stock through payroll deductions over a six month period. The purchase price is equal to 85 percent of the fair market value of the common stock on either the first or last day of the subscription period, whichever is lower. Purchases under the plan are limited to 10 percent of an employee s base salary. Under this plan 97,598 and 79,878 shares of common stock were purchased in the open market at a weighted-average share price of $33.12 and $23.11 during the nine months ended September 30, 2006 and 2005, respectively. For the three and nine months ended September 30, 2006, we recognized $490,000 and $1.1 million, respectively, 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.

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. As of September 30, 2006, no shares were purchased under this program. In October 2006, we purchased approximately 1.1 million shares of our common stock for a weighted average price of $29.22 per share, or $31.4 million.

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 reportable segments: Contracting Services (formerly known as our Deepwater Contracting), Shelf Contracting, Oil and Gas (formerly known as our 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 the 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 material intercompany transactions between the segments have been eliminated.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Revenues				
Contracting services	$ 122,843	$ 95,151	$ 336,464	$ 222,127
Shelf contracting	128,363	49,246	372,918	126,149
Oil and gas	145,032	75,463	306,455	206,439
Intercompany elimination	(21,814)	(10,522)	(44,752)	(19,271)
Total	$ 374,424	$ 209,338	$ 971,085	$ 535,444
Income from operations				
Contracting services	$ 24,803	$ 17,453	$ 64,189	$ 25,840
Shelf contracting[(1)]	44,844	15,597	143,330	29,775
Oil and gas	35,860	35,128	88,200	92,461
Production facilities equity investments[(2)]	(250)	(141)	(903)	(518)
Intercompany elimination	(6,007)		(7,005)	
Total	$ 99,250	$ 68,037	$ 287,811	$ 147,558
Equity in earnings of production facilities investments	$ 5,095	$ 3,049	$ 13,089	$ 7,486

(1) Included $(3.2) million and $(587,000) equity in (loss) earnings from investment in OTSL during the three and nine months ended September 30, 2006 and $672,000 for the three and nine months ended September 30, 2005.

(2) Represents selling and administrative expense of Production

Facilities incurred by us. See Equity in Earnings of Production Facilities Investments for earnings contribution.

	September 30, 2006	December 31, 2005
Identifiable Assets		
Contracting services	$ 902,847	$ 736,852
Shelf contracting	405,357	277,446
Oil and gas	2,202,074	478,522
Production facilities equity investments	199,669	168,044
Total	$ 3,709,947	$ 1,660,864

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Contracting services	$ 12,581	$ 10,413	$ 30,773	$ 18,417
Shelf contracting	9,233	109	13,979	854
Total	$ 21,814	$ 10,522	$ 44,752	$ 19,271

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Intercompany segment profit (which only relates to intercompany capital projects) during the three and nine months ended September 30, 2006 and 2005 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Contracting services	$ 1,909	$	$ 2,157	$
Shelf contracting	4,098		4,848	
Total	$ 6,007	$	$ 7,005	$

During the three and nine months ended September 30, 2006, we derived $50.9 million and $113.2 million, respectively, of our revenues from the U.K. sector, utilizing $208.1 million of our total assets in this region. During the three and nine months ended September 30, 2005, we derived $14.2 million and $62.9 million, respectively, of our revenues from the U.K. sector utilizing $136.8 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) in exchange for a revenue interest that is an overriding royalty interest of 25% of our 20% working interest. The investors of this entity include current and former Helix senior management. Production began in December 2003. Payments to OKCD from ERT totaled $8.8 million and $28.2 million in the three and nine months ended September 30, 2006, respectively, and $7.5 million and $20.8 million in the three and nine months ended September 30, 2005, respectively.

Note 18 Commitments and Contingencies

Commitments

We plan 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 $90 million, of which approximately $5.1 million had been incurred and $19.1 million had been committed at September 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 $7.8 million had been incurred and approximately $24.5 million had been committed at September 30, 2006.

In addition, in September 2006, we announced our plan to commit to the construction of a $160 million multi-service dynamically positioned dive support/ well intervention vessel that will be capable of working in the North Sea and West of Shetlands to support our contract extension to provide Light Well Intervention services for Shell UK Ltd. We expect this vessel to join our fleet in 2008. At September 30, 2006, we have committed approximately $3.8 million to this project through the use of a letter of credit.

Further, as of September 30, 2006, we committed to an additional estimated $159.0 million for development and drilling costs related to our oil and gas properties.

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Contingencies

We are involved in various routine legal proceedings, including 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, Cal Dive Offshore Ltd (CDO) entered into a subcontract with Seacore Marine Contractors Limited (Seacore) to provide the *Sea Sorceress* to Seacore for use in performing a contract between Seacore and Coflexip Stena Offshore Newfoundland (Coflexip). Due to various difficulties, that contract was terminated and an arbitration to recover damages was commenced. We were not a party to that arbitration. A liability finding was made by the arbitrator against Seacore and in favor of Coflexip. Seacore and Coflexip settled this matter, with Seacore paying Coflexip CAD$6.95 million. Seacore then initiated an arbitration proceeding against CDO seeking payment of that amount, and subsequently commenced lawsuit against us seeking the same recovery. Trial is scheduled for January 2007.

On December 2, 2005, ERT received notice (the December 2005 Order) from the U.S. Department of the Interior Minerals Management Service (MMS) that the price threshold for both oil and gas was exceeded for 2004 production and that royalties are due on such production notwithstanding the provisions of the Deep Water Royalty Relief Act of 2005 (DWRRA), which was intended to stimulate exploration and production of oil and natural gas in the deepwater Gulf of Mexico by providing relief from the obligation to pay royalty on certain federal leases. The only ERT leases affected by this dispute are Garden Banks Blocks 667, 668 and 669 (*Gunnison*) (ERT s Leases). On May 2, 2006, the MMS issued another order (the May 2006 Order) that superseded and replaced the December 2005 Order, and claimed that royalties are due on gas production in 2003 and 2004. The May 2006 Order also seeks interest on all royalties allegedly due. ERT filed a timely notice of appeal with respect to both the December 2005 Order and the May 2006 Order. Other operators in the Deep Water Gulf of Mexico who are seeking royalty relief under the DWRRA, including Kerr-McGee Oil and Gas Corporation (Kerr-McGee), the operator of *Gunnison*, have received notices similar to ERT s and have initiated an appeal process. In March of 2006, Kerr-McGee filed a lawsuit in federal district court challenging the enforceability of price thresholds in certain deepwater Gulf of Mexo Leases, such as ERT s. We do not anticipate that the MMS director will issue decisions in ERT s or the other companies administrative appeals until the Kerr-McGee litigation has been resolved. As a result of this dispute, we have recorded reserves for the disputed royalties (and any other royalties that may be claimed for production during 2005) plus interest at 5% for our portion of the *Gunnison* related MMS claim. The total reserved amount at September 30, 2006 was approximately $37.1 million. At this time, it is not anticipated that any penalties would be assessed even if ERT is unsuccessful in its appeal.

Although the above discussed matters may have the potential for additional liability and may have an impact on our consolidated financial results for a particular quarterly or annual reporting period, 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.

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.

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

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. Amendments to the Form S-1 were subsequently filed; however, the amended registration statement has not yet become effective. CDI represents our Shelf Contracting segment that provides manned diving, pipelay and pipe burial services to the offshore oil and natural gas industry. 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 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.

Note 22 Subsequent Events

Subsequent to September 30, 2006, we acquired a 58% interest in Seatrac Pty Ltd. (Seatrac) for total consideration of approximately $12.5 million, including approximately $9.1 million paid to existing shareholders, and $3.4 million for subscription of new Seatrac shares. The proceeds from the newly issued shares will be used by the entity to pay down existing indebtedness of approximately $1.9 million and to provide funding for capital expenditures of $1.5 million. Seatrac is a subsea well intervention and engineering services company located in Perth, Australia. Under the terms of the purchase agreement, we will be obligated to purchase the remaining 42% of the shares outstanding from the existing shareholders for $9.1 million upon Seatrac s successfully obtaining a significant commercial contract. In the event that the conditions required for the additional purchase are not met, we will be under no obligation to purchase the remaining 42% of Seatrac. In addition, the agreement with the existing shareholders provides for an earnout period of five years from the closing date for the purchase of the remaining 42% of Seatrac. If during this five-year period Seatrac achieves certain financial performance objectives, the shareholders will be entitled to additional consideration of approximately $4.6 million.

Further, in October 2006, we, along with Kommandor RØMØ A/S (Kommandor RØMØ), a Danish corporation, formed Kommandor, LLC (Kommandor), a Delaware limited liability company, to convert a ferry into a dynamically-positioned construction services vessel. Upon completion of the initial conversion, this vessel will be leased under a bareboat charter to ERT for further conversion and subsequent use as a floating production system in the Deepwater Gulf of Mexico, initially for the Phoenix field (see Liquidity and Capital Resources in Management s Discussion and Analysis of Financial Condition and Results of Operations). Our initial investment for our 50% interest in Kommandor was $15 million in cash. Further, we have agreed to provide a loan facility of up to $40 million and Kommandor RØMØ has agreed to loan $5 million to the newly formed entity for purposes of completing the initial conversion. Kommandor has received a commitment letter from a financial institution for term financing for $45 million of the initial conversion upon delivery of the vessel under the bareboat charter. Proceeds from this financing will be used to repay amounts loaned to Kommandor by us and Kommandor RØMØ. Conversion of the vessel is expected to be completed in two phases. The first phase is expected to be completed by the end of 2007. The second phase of the conversion is expected to be completed by mid 2008. Estimated cost of conversion for the second phase is approximately $100 million, in which we expect to participate 100%.

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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; 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 our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006; 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. Due to the Remington acquisition, we have identified additional critical accounting policies related to our Oil and Gas segment. Please read the following discussion in conjunction with our Critical Accounting Policies and Estimates as disclosed in our Form 10-K for the year ended December 31, 2005.

Exploratory Drilling Costs

The costs of drilling an exploratory well are capitalized as uncompleted wells pending the determination of whether the well has found proved reserves. If proved reserves are not found, these capitalized costs are charged to expense. On the other hand, the determination that proved reserves have been found results in the continued capitalization of the drilling costs of the well and its reclassification as a well containing proved reserves. At times, it may be determined that an exploratory well may have found hydrocarbons at the time drilling is completed, but it may not be possible to classify the reserves at that time. In this case, we may continue to capitalize the drilling costs as an uncompleted well beyond one year when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project, or the reserves are deemed to be proved. At that time the well is either reclassified as a proved well or is considered impaired and its costs, net of any salvage value, are charged to expense.

Occasionally, we may choose to salvage a portion of an unsuccessful exploratory well in order to continue exploratory drilling in an effort to reach the target geological structure/formation. In such cases, we charge only the unusable portion of the well bore to dry hole expense, and we continue to capitalize the costs associated with the salvageable portion of the well bore and add the costs to the new exploratory well. In certain situations, the well bore may be carried for more than one year beyond the date drilling in the original well bore was suspended. This may be due to the need to obtain, and/or analyze the availability of, equipment or crews or other activities necessary to pursue the targeted reserves or evaluate new or reprocessed seismic and geographic data. If, after we analyze the new information and conclude that we will not reuse the well bore or if the new exploratory well is determined to be unsuccessful after we complete drilling, we will charge the capitalized costs to dry hole expense.

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 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.

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

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 reportable segments: Contracting Services (formerly known as Deepwater Contracting), Shelf Contracting, Oil and Gas (formerly known as 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 material intercompany transactions between the segments have been eliminated.

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The following table sets forth for the periods presented vessel utilization rates for each of the major categories of our fleet, oil and gas prices realized, oil and gas production and reflects the increase or decrease in oil and gas sales revenue due to the changes in prices and volumes (in thousands, except percentages and prices):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
Our average vessel utilization rate[1]:				
Contracting Services:				
Pipelay	66%	100%	84%	88%
Well operations	86%	94%	80%	80%
Remotely operated vehicles	82%	67%	73%	68%
Shelf Contracting	83%	65%	84%	55%
Gas production volume (Mcf)	8,533	4,909	17,888	14,549
Gas sales revenue	$ 64,965	$ 41,703	$ 144,360	$ 107,548
Price per Mcf[2]	$ 7.61	$ 8.49	$ 8.07	$ 7.39
Increase (decrease) in gas sales revenue due to:				
Change in prices	$ (4,328)		$ 9,867	
Change in production volume	27,590		26,945	
Total increase in gas sales revenue	$ 23,262		$ 36,812	
Oil production volume (Bbls)	1,185	587	2,382	1,961
Oil sales revenue	$ 74,147	$ 31,859	$ 148,426	$ 93,753
Price per barrel[2]	$ 62.55	$ 54.30	$ 62.31	$ 47.80
Increase (decrease) in oil sales revenue due to:				
Change in prices	$ 4,841		$ 28,455	
Change in production volume	37,447		26,218	
Total increase in oil sales revenue	$ 42,288		$ 54,673	
Total production (Mcfe)	15,646	8,430	32,181	26,317
Price per Mcfe[2]	$ 8.89	$ 8.73	$ 9.10	$ 7.65

(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 calendar days in the applicable

period.

(2) Reflects realized prices, net of hedging impact.

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

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2006	**2005**	**2006**	**2005**
Lease operating expenses(1)	$2.16	$1.82	$2.17	$1.49
Depreciation, depletion and amortization	$3.13	$2.22	$2.77	$2.09
Selling and administrative expense	$0.50	$0.63	$0.56	$0.52

(1) Excludes exploration expense of $19.5 million, $928,000, $41.3 million and $6.0 million for the three months ended September 30, 2006 and 2005 and nine months ended September 30, 2006 and 2005, respectively. Exploration expense is not a component of lease operating expense.

Comparison of Three Months Ended September 30, 2006 and 2005

Net Revenues. Of the overall $165.1 million increase in revenues, $25.5 million was generated by the Contracting Services segment, $70.0 million by the Shelf Contracting segment and $69.6 million by the Oil and Gas 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 Helix Energy Limited acquisition in November 2005, offset partially by lower utilization in the Pipelay and Well Operations divisions due to vessel upgrades and unscheduled downtime. Shelf Contracting revenues increased due to improved market demand, much of which continued 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 September 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.

Oil and Gas revenue increased $69.6 million, or 92%, during the three months ended September 30, 2006 compared with the prior year period. The increase was primarily due to higher oil and natural gas production volumes primarily attributable to the Remington acquisition which closed on July 1, 2006. Production volume from the former Remington properties in the third quarter was approximately 7.3 Bcfe.

Gross Profit. Gross profit of $130.5 million for the three months ended September 30, 2006 represented a 57% increase compared to the $82.9 million recorded in the comparable prior year period. Contracting Services gross profit increased to $32.3 million for the three months ended September 30, 2006, from $24.4 million in the third quarter of 2005. The increase was primarily attributable to improved contract pricing for the Pipelay, Well Operations and ROV divisions and gross profit contribution from the Helix Energy Limited acquisition in November 2005. Shelf Contracting gross profit increased to $53.6 million for the three months ended September 30, 2006, from $17.7 million in the third 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.

Oil and Gas segment gross profit increased $3.8 million, to $44.6 million, due primarily to higher production volume as a result of the Remington acquisition. This increase was negatively impacted in the third quarter by the following:

Exploration expense of $19.5 million which included dry hole cost of approximately $16.9 million, delay rentals of approximately $509,000 and geological and geophysical (G&G) expense of approximately $2.1 million, compared with $928,000 of exploration costs in the third quarter of 2005.

Higher initial depreciation, depletion and amortization rates related to production from former Remington properties versus our historical rates on our mature properties; and

Hurricanes *Katrina* and *Rita* inspection and repair work which totaled approximately $5.8 million, partially offset by insurance recoveries of $1.6 million (none in the third quarter of 2005).

Gross margins in the third quarter of 2006 were 35% as compared to 40% in the comparable prior year period. Contracting Services margins remained at 29% in third quarter 2006, Shelf Contracting margins increased 9 points to 45% in third quarter 2006 from 36% in the prior year period, and Oil and Gas margins decreased 23 points to 31% in the third of quarter 2006 from 54% in the same period in 2005 due to the factors noted above.

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Selling and Administrative Expenses. Selling and administrative expenses of $30.3 million for the three months ended September 30, 2006 were $14.4 million higher than same period in 2005. The increase was due primarily to higher overhead to support our growth. Selling and administrative expenses was 8% of revenues for both third quarter of 2006 and 2005.

Equity in Earnings of Investments. Equity in earnings of our 50% investment in Deepwater Gateway, L.L.C. increased to $5.1 million in third quarter 2006 compared with $3.1 million in third quarter 2005. This increase is partially offset by equity loss of $3.2 million from our 40% minority ownership interest in OTSL in the third quarter 2006 compared with equity earnings of $672,000 in third quarter 2005.

Net Interest Expense and Other. We reported interest and other expense of $15.1 million for the three months ended September 30, 2006 compared to $2.8 million in the prior year period. Net interest expense of $15.1 million in the third quarter of 2006 was higher than the $2.2 million incurred in third quarter 2005 due primarily to the $835 million Term Loan we entered into in July 2006. Offsetting the increase in interest expense was $2.6 million of capitalized interest in third quarter of 2006, compared with $526,000 in the same period in 2005, which related primarily to our investment in Independence Hub and various ERT properties.

Provision for Income Taxes. Income taxes increased to $31.4 million for the three months ended September 30, 2006 compared to $25.1 million in the prior year period, primarily due to increased profitability. The effective tax rate of 35% in the third quarter of 2006 was lower than the 37% effective tax rate for third 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 Nine Months Ended September 30, 2006 and 2005

Net Revenues. Of the overall $435.6 million increase in revenues, $102.0 million was generated by the Contracting Services segment, $233.6 million by the Shelf Contracting segment and $100.0 million by the Oil and Gas segment. Contracting Services revenues increased primarily due to improved market demand (resulting in improved contract pricing for the Pipelay, Well Operations divisions and the ROV division) and the addition of the *Express* acquired from Torch in 2005 and Helix Energy Limited acquired in 2005. In addition, revenue increased due to improved market demand, much of which was the result of damages sustained in the 2005 hurricanes in the Gulf of Mexico. This resulted in significantly improved utilization rates and an overall increase in pricing for our Shelf Contracting services.

Oil and Gas revenue increased $100.0 million, or 48%, during the nine months ended September 30, 2006 compared with the prior year period. The increase was primarily due to increases in oil and natural gas production. Production volume increased to 32.2 Bcfe, or approximately 22% from the same period in 2005. The increase was mainly attributable to the full third quarter impact of the Remington acquisition, partially offset by continued pipeline shut-ins on certain fields. Oil and Gas revenue also increased due to higher oil and gas prices realized in the nine months ended September 30, 2006 as compared to the same period in 2005. The average realized natural gas price, net of hedges in place, during the nine months ended September 30, 2006 was 9% higher than the price realized in 2005. Average realized oil prices, net of hedges in place, increased 30% compared with the average price realized in the same period in 2005.

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Gross Profit. Gross profit of $364.4 million for the nine months ended September 30, 2006 represented a 95% increase compared to the $187.2 million recorded in the comparable prior year period. Contracting Services gross profit increased to $91.7 million for the nine months ended September 30, 2006, from $42.2 million in the first nine months of 2005. The increase was primarily attributable to improved contract pricing for the Pipelay, Well Operations and ROV divisions, including the contribution of the *Express* for the nine months ended September 30, 2006.

Shelf Contracting gross profit increased to $164.0 million for the nine months ended September 30, 2006, from $37.6 million in the first nine months of 2005. As previously discussed, the increase was primarily attributable to additional gross profit derived from the Torch and Acergy acquisitions, improved utilization rates and increased contract pricing.

Oil and Gas gross profit increased slightly from $107.4 million to $108.7 million. Gross profit was impacted by $41.3 million of exploration costs incurred during the nine months ended September 30, 2006 compared with $6.0 million incurred in the same period in 2005. The increase in exploration costs was primarily due to dry hole costs of $21.7 million 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 in the first quarter of 2006. In addition, we incurred dry hole costs totaling approximately $15.9 million in the third quarter of 2006 associated with two deep shelf wells commenced by Remington prior to the acquisition. In addition, included in exploration costs, we expensed $2.9 million of G&G costs in the first nine months of 2006, compared with $5.3 million in the same period in 2005. Lastly, we expensed inspection and repair costs of approximately $14.9 million as a result of Hurricanes *Katrina* and *Rita*, partially offset by $4.3 million in insurance recoveries in the first nine months of 2006. No hurricane inspection and repair costs were incurred in the nine months ended September 30, 2005. These decreases were offset by higher commodity prices realized and oil and gas production as discussed above. In addition, in 2005 ERT recorded $2.7 million of losses associated with hedge instrument ineffectiveness as a result of production shut-ins caused by the aforementioned hurricanes. No hedge ineffectiveness was recorded in 2006.

Gross margins in the first nine months of 2006 were 38% as compared to 35% in the comparable prior year period. Contracting Services margins increased 9 points to 30% in the nine months ended September 30, 2006 compared with 21% in the prior year period, and Shelf Contracting margins increased 16 points to 46% in the first nine months of 2006 from 30% in the prior year period. The increases were due to the factors noted above. In addition, margins in the Oil and Gas segment decreased 17 points to 35% in the nine months ended September 30, 2006 from 52% in the same period in 2005, primarily due to the dry hole costs. Oil and Gas 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 $5.3 million of G&G costs for ERT s offshore property acquisitions.

Selling and Administrative Expenses. Selling and administrative expenses of $78.8 million for the nine months ended September 30, 2006 were $37.2 million higher than the $41.6 million incurred in the nine months ended September 30, 2005. The increase was due primarily to higher overhead to support our growth. Selling and administrative expenses were at 8% of revenues for both periods in 2006 and 2005.

Equity in Earnings of Investments. Equity in earnings of our 50% investment in Deepwater Gateway, L.L.C. increased to $13.1 million for the nine months ended September 30, 2006 compared with $7.5 million in the first nine months of 2005. Further, equity in earnings (losses) from our 40% minority ownership interest in OTSL for the nine months ended September 30, 2006 totaled approximately $(587,000) compared with $672,000 in the first nine months of 2005.

Net Interest Expense and Other. We reported interest and other expense of $20.5 million for the nine months ended September 30, 2006 compared to $4.9 million in the prior year period. Net interest expense of $20.9 million for the nine months ended September 30, 2006 was higher than the $4.2 million incurred in the same period in 2005. Approximately $15.7 million of the increase was related to our $835 million Term Loan which closed in July 2006 and $2.4 million of the increase was related to our $300 million Convertible Senior Notes which closed in March 2005. Offsetting the increase in interest expense was $5.0 million of capitalized interest in the nine months ended September 30, 2006, compared with capitalized interest of $1.1 million in the prior year period, which related primarily to our investment in Independence Hub and various ERT properties.

Provision for Income Taxes. Income taxes increased to $96.4 million for the nine months ended September 30, 2006 compared to $54.4 million in the prior year period, primarily due to increased profitability. The effective tax rate of 34% for the nine months ended September 30, 2006 was lower than the 36% effective tax rate for same period 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.

LIQUIDITY AND CAPITAL RESOURCES

Total debt as of September 30, 2006 was $1.3 billion, comprised primarily of $835 million term loan which matures in 2013, $300 million of Convertible Senior Notes which mature in 2025 and $131.3 million of MARAD debt which matures in 2027. We also have a $300 million revolving facility which was undrawn as of September 30, 2006. In addition, as of September 30, 2006, we had $48.4 million of restricted cash (included in other assets, net). For a discussion of expected uses of our cash related to the exploration and development of our oil and gas properties, see Investing Activities below.

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. As of September 30, 2006, no shares were purchased under this program. In October 2006, we purchased approximately 1.1 million shares of our common stock for a weighted average price of $29.22 per share, or $31.4 million.

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 and variable interest rate exposure. All derivatives are reflected in our balance sheet at fair value, unless otherwise noted.

Commodity Hedges

During 2005 and the first nine months 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 asset (liability) of $3.5 million and $(13.4) million as of September 30, 2006 and December 31, 2005, respectively. We recorded unrealized gains of approximately $8.6 million and $11.0 million, net of tax expense of $4.6 million and $5.9 million, during the three and nine months ended September 30, 2006, respectively, in accumulated other comprehensive income, a component of shareholders equity, as these hedges were highly effective. For the three and nine months ended September 30, 2005, we recorded $11.7 million and $18.4 million, respectively, of unrealized losses, net of tax benefit of $6.3 million and $9.9 million, respectively. During the three and nine months ended September 30, 2006, we reclassified approximately $614,000 and $6.9 million of gains, respectively, from other comprehensive income to net revenues upon the sale of the related oil and gas production. For the three and nine months ended September 30, 2005, we reclassified approximately $3.2 million and $6.1 million, respectively, of losses from other comprehensive income to net revenues.

During the third quarter of 2005, hedge ineffectiveness related to cash flow hedge was a loss of $1.8 million, net of tax benefit of $951,000. The amount was recorded in earnings as a reduction in net revenues. Hedge ineffectiveness resulted from ERT s inability to deliver contractual oil and gas production in fourth quarter 2005 due primarily to the effects of Hurricanes *Katrina* and *Rita*. No hedge ineffectiveness was recorded during the three and nine months ended September 30, 2006.

As of September 30, 2006, we had oil forward sales contracts for the period from October 2006 through June 2007. The contracts cover an average of 35.3 MBbl per month at a weighted average price of $70.63. In addition, we had natural gas forward sales contracts for the period from October 2006 through June 2007. The contracts cover an average of 567,083 MMbtu per month at a weighted average price of $9.26. Hedge accounting does not apply to these contracts.

Interest Rate Hedge

In September 2006, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to a portion of our interest payment for our Term Loan beginning October 3, 2006. All of these interest rate swaps qualify for hedge accounting.

Operating Activities. The increase in cash flow from operating activities for the nine months ended September 30, 2006 as compared to the same period in 2005 was due primarily to an increase in profitability ($88.2 million), which included higher depreciation and amortization of $47.5 million and deferred taxes of $14.6 million as compared to the same prior year period, and dry hole expenses of $37.6 million during the nine months ended September 30, 2006. In addition, collections related to our trade receivables improved during the nine months ended September 30, 2006 as compared to the same period in prior year, excluding accounts receivable acquired in the Remington transaction. These increases to cash flow from operations were partially offset by decreases in accounts payable and accrued liabilities, excluding accounts payable and accrued liabilities assumed in the Remington transaction and a non-cash capital expenditure accrual of $71.5 million. In addition, cash flow from operating activities 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 nine months 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 nine months of 2006 was $825.1 million for Remington, offset by $53.0 million of cash acquired. As part of the merger consideration, we issued 13,032,528 shares of our common stock to Remington stockholders as non-cash consideration. In addition, capital expenditures for the first nine months of 2006 included $163.3 million for ERT well exploitation programs, further *Gunnison* field development and other deepwater development and exploratory costs, $69.0 million related to our Contracting Services segment (including $27.5 million for the purchase of the *Caesar*) and $21.1 million related to our Shelf Contracting segment. 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). In the third quarter of 2006, we also completed the Fraser acquisition for cash of approximately $24.8 million, offset by $2.3 million of cash acquired. Included in the capital expenditures during the first nine months of 2005 was $163.5 million for the Murphy properties acquisition by ERT, $85.6 million for the acquisition of the Torch assets, $49.6 million for ERT well exploitation programs and further *Gunnison* field development, $10.9 million for Canyon Offshore ROV and trencher systems and approximately $6.7 million for vessel upgrades on certain Contracting Services and Shelf Contracting vessels.

As of September 30, 2006, we have the following investments that are accounted for under the equity method of accounting:

Deepwater Gateway, L.L.C. Our investment in Deepwater Gateway, L.L.C. totaled $122.5 million as of September 30, 2006.

Independence. Our investment in Independence was $76.8 million as of September 30, 2006, and our total investment is expected to be approximately $84 million. We expect to complete our investment by the end of 2006. Mechanical completion for Independence Hub is expected in the first quarter of 2007.

OTSL. Our investment in OTSL totaled $10.8 million at September 30, 2006. 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. We have agreed to extend the lump sum principal payment due date and have increased the interest rate to three-month LIBOR plus 4.0%. We have reported a net loss of $587,000 for the nine months ended September 30, 2006 related to our investment in OTSL. This net loss is an impairment indicator. However, we believe the current operating trend is temporary and have determined that the fair value of this investment, based on an estimate of its discounted cash flows, exceeds its carrying amount. As a result, there was no impairment at September 30, 2006.

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

	Nine Months Ended September 30,	
	2006	**2005**
Deepwater Gateway, L.L.C.(1)	$	$ 72,000
Independence Hub, LLC	23,092	28,486
OTSL(2)		8,400
Total	$ 23,092	$ 108,886

(1) Contribution made in the nine months ended September 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.

(2) Includes non-cash contribution of the *Witch Queen* in 2005 of \$6.7 million (net of \$296,000 of transaction costs).

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

	Nine Months Ended September 30,	
	2006	2005
Deepwater Gateway, L.L.C	$ 7,750	$ 16,100
Independence Hub, LLC		
OTSL	68	
Total	$ 7,818	$ 16,100

Oil and Gas

As of September 30, 2006, we had $33.4 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 acquisition in 2002. Under the purchase agreement for the acquisition, ERT was 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 has fully escrowed the requirement as of September 30, 2006. ERT may use the restricted cash for decommissioning the related field.

On July 1, 2006, we acquired 100% of Remington 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 stockholders and funded the cash portion of the Remington acquisition (approximately $806.8 million) and transaction costs (approximately $18.3 million) through the Term Loan.

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 $21.7 million was charged to earnings during the nine months ended September 30, 2006. We continue to evaluate various options with the operator for recovering the potential reserves. Further, in the third quarter of 2006, we expensed approximately $15.9 million of exploratory drilling cost related to two deep shelf properties (acquired in the Remington acquisition which were in process prior to July 1, 2006) in which we determined commercial quantities of hydrocarbons were not discovered.

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 that Norsk Hydro would not pursue its 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. We recorded a gain of $2.2 million in the third quarter of 2006 related to this sale. The sale of this asset constituted a disposition under the Credit Agreement, which requires either prepayment of the Term Loan by the amount of the sale or escrow of the proceeds until the amount can be invested in qualified replacement collateral. We elected to transfer the $15 million cash received into an escrow account held by Bank of America for use in the purchase of or investment in qualified replacement assets. The funds held in escrow will be released upon submission of qualified capital expenditures to Bank of America. We expect to receive the funds from the escrow in the fourth quarter of 2006. The restricted cash is reported in other assets, net as of September 30, 2006.

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The Tiger Prospect, located at a water depth of 1,850 feet, initiated sidetrack drilling operations in May 2006. The successful well has been tied back to a host platform and production is expected to begin in the fourth quarter of 2006.

In August 2006, ERT acquired a 100% working interest in the Typhoon oil field (Green Canyon Blocks 236/237), the Boris oil field (Green Canyon Block 282) and the Little Burn oil field (Green Canyon Block 238) for assumption of certain decommissioning liabilities. We have received SOP approval from the MMS. ERT will also have farm-in rights on five near-by blocks where three prospects have been identified in the Typhoon mini-basin. Following the acquisition of the Typhoon field and MMS approval, we renamed the field Phoenix. We expect to deploy a minimal floating production system over Phoenix in mid-2008, with production scheduled to commence in the third quarter of 2008. Specific field drilling, completion and infrastructure cost is expected to be approximately $135 million (exclusive of the cost of the FPS). See Note 22 for further detail on the floating production system.

As of September 30, 2006, we committed to an additional estimated $159.0 million for development and drilling costs related to our oil and as properties.

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).

Shelf Contracting

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. The balance of the promissory note as of September 30, 2006 was $1.5 million. We expect to collect the remaining balance. 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 September 30, 2006, was approximately $17.8 million. In addition, under the lease agreement, if the lessee exercises the purchase option, 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. If the lessee elects not to exercise its option to purchase the remaining 50% interest in the vessel, minimum future rentals to be received on this lease are $68.0 million through January 2016.

Also, in a bankruptcy auction held in June 2005, we were the high bidder for seven vessels, including the *Express*, and a portable saturation system for approximately $85.6 million, including certain costs incurred related to the transaction.

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 $90 million, of which approximately $5.1 million had been incurred and $19.1 million had been committed at September 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 the proportionate share of the cost of the vessel plus the actual cost of conversion (conversion cost is estimated to be $90 million). The third party must make all contributions to Vulcan on or before March 31, 2007.

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 $7.8 million had been incurred and approximately $24.5 million had been committed at September 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., 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. Proceeds from the credit facilities were used to fund the cash portion of the Remington acquisition and for general corporate purposes. The Term Loan matures on July 1, 2013 and is subject to scheduled principal payments of $2.1 million quarterly. We made our first payment on October 2, 2006. The Revolving Loans mature on July 1, 2011.

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 two payments during each of the nine month periods ended September 30, 2006 and 2005 totaling $3.6 million and $4.3 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 September 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.

Other

Related to our $55 million cumulative convertible preferred stock, we paid $2.7 million and $1.7 million in dividends for the nine months ended September 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, we entered into a two-year note payable to former owners totaling approximately 3.1 million British Pounds, or approximately $5.6 million, on November 3, 2005 ($5.9 million at September 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 $11.1 million and $11.0 million in the nine months ended September 30, 2006 and 2005, respectively.

During the nine months ended September 30, 2006 and 2005, we made payments of $2.2 million and $2.1 million, respectively, on capital leases relating to Canyon. The only other financing activity during the nine months ended September 30, 2006 and 2005 involved exercises of employee stock options of $8.8 million and $7.2 million, respectively. In addition, in the first nine months of 2006, financing activities included $7.8 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.

In addition, a subsidiary of CDI intends to enter into a credit agreement with Bank of America, N.A., as administrative agent, J.P. Morgan Securities Inc. and Banc of America Securities LLC, as joint lead arrangers, and other financial institutions as lenders and ancillary agents identified therein, pursuant to which the borrower may have outstanding at any one time up to $250 million in revolving loans under a five-year revolving credit facility. Within that borrowing limit, the borrower may request letters of credit at any one time outstanding up to $10 million.

The following table summarizes our contractual cash obligations as of September 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
Term Loan	835,000	8,400	16,800	16,800	793,000
MARAD debt	131,287	3,823	8,228	9,069	110,167
Loan notes	5,871		5,871		
Capital leases	4,667	2,504	2,163		
Investments in Independence Hub, LLC	11,800	11,800			
Drilling and development costs	159,000	136,300	22,700		
Property and equipment[3]	43,600	43,600			
Operating leases[4]	49,827	30,883	7,732	4,741	6,471
Other[5]	8,190	4,400	3,790		
Total cash obligations	$ 1,549,242	$ 241,710	$ 67,284	$ 30,610	$ 1,209,638

(1) Excludes guarantee of performance related to the construction of the Independence Hub platform under Independence Hub, LLC (estimated to be immaterial at September 30, 2006) and unsecured letters of credit outstanding at September 30, 2006 totaling $7.8 million. These letters of credit primarily guarantee various contract bidding, insurance activities and shipyard commitments.

(2) Maturity 2025. Can be converted prior to stated maturity 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) 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 conversion costs are estimated to be approximately $90 million, of which approximately $5.1 million had been incurred and approximately $19.1 million was committed at September 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 $7.8 million had been incurred and approximately $24.5 million had been committed at September 30, 2006.

(4) Operating leases included facility leases and vessel charter leases. Vessel charter lease commitments at September 30, 2006 were approximately $12.1 million.

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

Finally, in connection with our business strategy, we regularly evaluate acquisition opportunities (including additional vessels as well as interests in offshore natural gas and oil properties). We believe internally generated cash flow, borrowings under existing credit facilities and use of project financing 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.

Contingencies

In December 2005 and at subsequent dates, ERT received notice from the MMS that the price threshold was exceeded for 2004 oil and gas production and for 2003 gas production, and that royalties are due on such production notwithstanding the provisions of the DWRRA. As of September 30, 2006, we have approximately $37.1 million accrued for the related royalties and interest. See Note 18 for a detailed discussion of this contingency.

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Subsequent Events

Subsequent to September 30, 2006, we acquired a 58% interest in Seatrac for total consideration of approximately $12.5 million, including approximately $9.1 million paid to existing shareholders, and $3.4 million for subscription of new Seatrac shares. Under the terms of the purchase agreement, we will be obligated to purchase the remaining 42% of the shares outstanding from the existing shareholders for $9.1 million upon Seatrac s successfully obtaining a significant commercial contract. In the event that the conditions required for the additional purchase are not met, we will be under no obligation to purchase the remaining 42% of Seatrac. In addition, the agreement with the existing shareholders provides for an earnout period of five years from the closing date for the purchase of the remaining 42% of Seatrac. If during this five-year period, Seatrac achieves certain financial performance objectives, the shareholders will be entitled to additional consideration of approximately $4.6 million.

Further, in October 2006, we, along with Kommandor RØMØ A/S (Kommandor RØMØ), a Danish corporation, formed Kommandor, LLC (Kommandor), a Delaware limited liability company, to convert a ferry into a dynamically-positioned construction service vessel. Upon completion of the initial conversion, this vessel will be leased under a bareboat charter to ERT for further conversion and subsequent use as a floating production unit in the Deepwater Gulf of Mexico, initially for the Phoenix field. Our initial investment in Kommandor was $15 million in cash. Further, we have agreed to provide a loan facility of up to $40 million and Kommandor RØMØ has agreed to loan $5 million to the newly formed entity for purposes of completing the initial conversion. Kommandor has received a commitment letter from a financial institution for term financing of $45 million of the initial conversion upon delivery of the vessel under the bareboat charter. Proceeds from this financing will be used to repay amounts loaned to the entity by us and Kommandor RØMØ. Conversion of the vessel is expected to be completed in two phases. The first phase is expected to be completed by the end of 2007. The second phase of the conversion is expected to be completed by mid 2008. Estimated cost of conversion for the second phase is approximately $100 million, in which we expect to participate 100%.

Item 3. Quantitative and Qualitative Disclosure about Market Risk

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

Interest Rate Risk

As of September 30, 2006, approximately 66% of our outstanding debt was based on floating rates. As a result, we are subject to interest rate risks. In September 2006, we entered into various cash flow hedging interest rate swaps to stabilize cash flows relating to $200 million of our interest payment for our Term Loan beginning October 3, 2006. Excluding the portion of our debt for which we have interest rate swaps in place, the interest rate applicable to our remaining variable rate debt may rise, increasing our interest expense. The impact of market risk is estimated using a hypothetical increase in interest rates by 100 basis points for our variable rate long-term debt that is not hedged. Based on this hypothetical assumption, we would have incurred an additional $2.1 million in interest expense for both three and nine months ended September 30, 2006. Interest rate risk was immaterial in 2005 as none of our outstanding debt at September 30, 2005 was based on floating rates.

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.

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As of September 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:			
October 2006 December 2006	Collar	125 MBbl	$ 44.00 - $70.48
January 2007 December 2007	Collar	50 MBbl	$ 40.00 - $62.15
Natural Gas:			
October 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	333,333 MMBtu	$ 7.50 - $11.23

We have not entered into any hedge instruments subsequent to September 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 September 30, 2006, we had oil forward sales contracts for the period from October 2006 through June 2007. The contracts cover an average of 35.3 MBbl per month at a weighted average price of $70.63. In addition, we had natural gas forward sales contracts for the period from October 2006 through June 2007. The contracts cover an average of 567,083 MMbtu per month at a weighted average price of $9.26. Hedge accounting does not apply to these contracts.

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 nine months ended September 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 7% of our assets are impacted by changes in foreign currencies in relation to the U.S. dollar at September 30, 2006. We recorded unrealized gains of $1.3 million and $10.3 million to our equity account for the three and nine months ended September 30, 2006, respectively, and $1.3 million and $8.0 million of unrealized losses to our equity account for the three and nine months ended September 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 nine months ended September 30, 2006 and 2005, respectively, were not material to our results of operations or cash flows.

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In addition, FDI has operations in the Southeast Asia sector and conducts the majority of its operations in this region 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 months ended September 30, 2006 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 and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the fiscal quarter ended September 30, 2006. Based on this evaluation, the principal executive officer and the principal financial officer have concluded that our disclosure controls and procedures were effective as of the end of the fiscal quarter ended September 30, 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 have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. On July 1, 2006, we completed the acquisition of Remington Oil and Gas Corporation. We continue to integrate Remington s historical internal controls over financial reporting into our own internal controls over financial reporting. This integration may lead to our making changes in our or Remington s historical internal controls over financial reporting in future fiscal periods.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

In addition to the risk factors disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005 and our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, we add the following risk factors as a result of recent events:

Natural gas and oil prices are volatile, which makes future revenue uncertain.

Our financial condition and results of operations depend on the prices we receive for the oil and gas we produce. The market prices for oil and gas are subject to fluctuation in response to events beyond our control, such as:

- supply of and demand for oil and gas;
- market uncertainty;
- worldwide political and economic instability; and
- government regulations.

Oil and gas prices have historically been volatile, and such volatility is likely to continue. Our ability to estimate the value of producing properties for acquisition and to budget and project the financial return of exploration and development projects is made more difficult by this volatility. In addition, to the extent we do not forward sell in order to hedge our exposure to price volatility, a dramatic decline in such prices could have a substantial and material effect on:

- our revenues;
- financial condition;
- results of operations;
- our ability to increase production and grow reserves in an economically efficient manner; and
- our access to capital.

Our commodity price risk management related to some of our oil and gas production may reduce our potential gains from increases in oil and gas prices.

Oil and gas prices can fluctuate significantly and have a direct impact on our revenues. To manage our exposure to the risks inherent in such a volatile market, from time to time, we have forward sold for future physical delivery a portion of our future production. This means that a portion of our production is sold at a fixed price as a shield against dramatic price declines that could occur in the market. In addition, we have entered into costless collar contracts related to some of our future oil and as production as well. We may from time to time engage in other hedging activities that limit our upside potential from price increases. These sales activities may limit our benefit from dramatic price increase.

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We are in part dependent on third parties with respect to the transportation of our oil and gas production and in certain cases, third party operators who influence our productivity.

Notwithstanding our ability to produce, we are dependent on third party transporters to bring our oil and gas production to the market. In the event a third party transporter experiences operational difficulties, due to force majeure, pipeline shut-ins, or otherwise, this can directly influence our ability to sell commodities that we are able to produce. In addition, with respect to oil and gas projects that we do not operate, we have limited influence over operations, including limited control over the maintenance of both safety and environmental standards. The operators of those properties may, depending on the terms of the applicable joint operating agreement:

- refuse to initiate exploration or development projects;

- initiate exploration or development projects on a slower or faster schedule than we prefer;

- due to their own liquidity and cash flow problems, delay the pace of drilling or development; and/or

- drill more wells or build more facilities on a project than we can afford, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities

Government regulation may affect our ability to conduct operations, and the nature of our business exposes us to environmental liability.

Numerous federal and state regulations affect our oil and gas operations. Current regulations are constantly reviewed by the various agencies at the same time that new regulations are being considered and implemented. In addition, because we hold federal leases, the federal government requires us to comply with numerous additional regulations that focus on government contractors. The regulatory burden upon the oil and gas industry increases the cost of doing business and consequently affects our profitability.

Our operations are subject to a variety of national (including federal, state and local) and international laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that carry substantial administrative, civil and possibly criminal penalties for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials including oil into the environment, and such liability may be imposed on us even if the acts that resulted in the releases were in compliance with all applicable laws at the time such acts were performed.

We operate in foreign jurisdictions that have various types of governmental laws and regulations relating to the discharge of oil or hazardous substances and the protection of the environment. Pursuant to these laws and regulations, we could be held liable for remediation of some types of pollution, including the release of oil, hazardous substances and debris from production, refining or industrial facilities, as well as other assets we own or operate or which are owned or operated by either our customers or our sub-contractors.

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Management believes that we are in compliance in all material respects with all applicable environmental laws and regulations to which we are subject. We do not anticipate that compliance with existing environmental laws and regulations will have a material effect upon our capital expenditures, earnings or competitive position. However, changes in the environmental laws and regulations, or claims for damages to persons, property, natural resources or the environment, could result in substantial costs and liabilities, and thus there can be no assurance that we will not incur significant environmental compliance costs in the future. Such environmental liability could substantially reduce our net income and could have a significant impact on our financial ability to carry out our oil and gas operations.

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

Issuer Purchases of Equity Securities

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced program	(d) Maximum value of shares that may yet be purchased under the program(2)
July 1 to July 31, 2006		$		$ N/A
August 1 to August 31, 2006				N/A
September 1 to September 30, 2006(1)	1,065	38.46		N/A
	1,065	$ 38.46		$ N/A

(1) 1,065 shares subject to restricted share awards were withheld to satisfy tax obligations arising upon the vesting of restricted shares.

(2) In October 2006, we purchased approximately 1.1 million shares of our common stock

for a weighted average price of $29.22 per share, or $31.4 million, under our stock buy back program which was approved by our board of directors in June 2006 for up to $50 million.

Item 6. Exhibits

10.1 Termination Agreement between James Lewis Connor, III and the Company dated August 31, 2006[(1)]

10.2 Employment Agreement between Alisa B. Johnson and the Company dated September 18, 2006[(1)]

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

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

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

32.1 Section 1350 Certification of Principal Executive Officer, Owen Kratz, Executive Chairman[(2)]

32.2 Section 1350 Certification of Principal Financial Officer, A. Wade Pursell, Chief Financial Officer[(2)]

99.1 Report of Independent Registered Public Accounting Firm[(1)]

(1) Filed herewith

(2) Furnished herewith

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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: November 7, 2006	By:	**/s/ Owen Kratz**
		Owen Kratz Executive Chairman
Date: November 7, 2006	By:	**/s/ A. Wade Pursell**
		A. Wade Pursell Senior Vice President and Chief Financial Officer

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