UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant To Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): May 11, 2006

SUPERIOR ENERGY SERVICES, INC.

(Exact name of registrant as specified in its charter)

Commission File No. 0-20310

Delaware (State or other jurisdiction of incorporation or organization)	75-2379388 (I.R.S. Employer Identification No.)
1105 Peters Road Harvey, Louisiana (Address of principal executive offices)	70058 (Zip Code)

(504) 362-4321
(Registrant's telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligations of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events

During the first quarter of 2006, we modified the manner in which we report and evaluate segment information due to changes in our business. In February 2006, we sold our environmental subsidiary, which comprised a large part of the other oilfield services segment. The remaining businesses, which include platform and field management services, environmental cleaning services and the sale of drilling instrumentation equipment, are impacted by similar factors that affect the well intervention segment. Therefore, we have combined our other oilfield services segment into the well intervention segment because the combination of the well intervention and other oilfield services segments better reflects the way management evaluates our results. This Form 8-K is being filed for the purpose of amending and revising Items 7 and 8 of our Annual Report on Form 10-K for the year ended December 31, 2005 to combine our other oilfield services segment into our well intervention segment (see Note 14 to the Consolidated Financial Statements). By amending our segment presentation contained in the Annual Report on Form 10-K for the year ended December 31, 2005, our historical financial statements will be presented on a basis consistent with our interim financial statements.

This Form 8-K amends only the items specified in the preceding paragraph. All other components of the original Annual Report on Form 10-K for the year ended December 31, 2005 remain unchanged, including consolidated net income, total assets, liabilities and stockholders' equity. This amendment, including the financial statements and notes hereto, does not reflect events occurring after the date of the original filing of the Annual Report on Form 10-K for the year ended December 31, 2005.

The revised financial statements and Management's Discussion and Analysis of Financial Condition and Results of Operations are filed hereto under Item 8.01 as Exhibits 99.1 and 99.2.

Item 9.01 Financial Statements and Exhibits

Exhibit No.	Description
23.1	Consent of KPMG LLP.
99.1	Management's Discussion and Analysis of Financial Condition and Results of Operations under Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2005, conformed to reflect segment reporting changes.
99.2	Audited consolidated financial statements of the Company as of December 31, 2005 and 2004 and for each of the three years ended December 31, 2005, conformed to reflect segment reporting changes.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) 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.

SUPERIOR ENERGY SERVICES, INC.

Date: May 11, 2006	By: /s/ Robert S. Taylor
	Robert S. Taylor Executive Vice President, Treasurer and Chief Financial Officer (Principal Financial and Accounting Officer)

INDEX TO EXHIBITS

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EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Superior Energy Services, Inc.:

We consent to incorporation by reference in Registration Statements No. 333-35286 and No. 333-123442 on Form S-3 and No. 333-12175, No. 333-43421, No. 333-33758, No. 333-60860, No. 333-101211, No. 333-116078 and No. 333-125316 on Form S-8 of Superior Energy Services, Inc. of our reports dated March 8, 2006, except as to Note 14, which is as of May 11, 2006, with respect to the consolidated balance sheets of Superior Energy Services, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2005, the related consolidated financial statement schedule, which report appears in the May 11, 2006 current report on Form 8-K of Superior Energy Services, Inc.

/s/ KPMG LLP

New Orleans, Louisiana
May 11, 2006

EXHIBIT 99.1

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements included in Exhibit 99.2 of this Current Report on Form 8-K. The following information contains forward-looking statements, which are subject to risks and uncertainties. Should one or more of these risks or uncertainties materialize, our actual results may differ from those expressed or implied by the forward-looking statements. See "Forward-Looking Statements" at the beginning of our Annual Report on Form 10-K for the year ended December 31, 2005.

Executive Summary

We are a leading provider of specialized oilfield services and equipment focused on serving the drilling-related needs of oil and gas companies primarily through our rental tools segment, and the production-related needs of oil and gas companies through our well intervention, rental tools and marine segments. In recent years, we have expanded geographically so that we now have a growing presence in select domestic land and international markets. We also own and operate, through our subsidiary SPN Resources, LLC, mature oil and gas properties in the Gulf of Mexico.

The oil and gas industry remains highly cyclical and seasonal. Activity levels in our service and rental tools segments are driven primarily by traditional energy industry activity indicators, which include current and expected future commodity prices, drilling rig count, oil and gas production levels, and customers' capital spending allocated for drilling and production.

The primary factors driving our performance in 2005 were (1) increased customer spending levels on finding and replacing oil and gas reserves due to high commodity prices; (2) increased customer focus on replacing reserves through production-enhancement projects in existing wells; and (3) the active hurricane season, which disrupted a strong Gulf of Mexico market, but created incremental long-term demand for our products and services.

In 2005, activity across all segments increased throughout the year, particularly in the Gulf of Mexico. However, the extraordinarily active hurricane season — highlighted by damage caused by Hurricanes Katrina and Rita — disrupted most Gulf of Mexico-based well intervention service and rental tool activity for almost three months following the storms.

By mid-November, pre-storm Gulf activity levels resumed for well intervention services and rental tools and by year-end demand for most services and tools were exceeding those levels. The marine segment participated in post-storm damage assessment and construction support projects throughout the fourth quarter. By the end of the year, liftboat demand continued to grow due to the post-hurricane construction and repair work, coupled with well intervention work that was deferred prior to the storms. This led to unprecedented dayrates for liftboats as year-end dayrates were 50% higher than rates in August 2005, and 30% higher than dayrates we were generating during the second and third quarters of 2001 when prior peak dayrates were established. Also, for the first time in several years, we were able to achieve meaningful price increases for some of our well intervention services. Financial performance for services has traditionally been driven by volume, or utilization, while pricing improvement has been difficult to achieve. However, pent-up demand and incremental work created by hurricane damage have allowed us to raise prices on some services by as much as 20%.

The active hurricane season also caused significant damage to the industry's Gulf of Mexico infrastructure. Our participation in the Gulf of Mexico repair efforts include project management; marine and well control engineering; relief well planning, supervision and execution; well intervention planning; offshore supervision and offshore site and activity management; well abandonment; and specialty equipment and tools. In addition, we will provide our liftboats, well intervention services and rental tools to many more projects that we are not managing.

Our oil and gas production remained largely shut-in following the hurricanes due to hurricane damage. During the fourth quarter, we were repairing our properties and awaiting repairs to pipelines owned by third parties. Average production during the second quarter of 2005, prior to the active hurricane season, was approximately 7,200 barrels of oil equivalent (“boe”) per day. However, in the third and fourth quarters, production averaged approximately 4,600 boe per day and 1,100 boe per day, respectively. All of our production is expected to be restored by the end of the first quarter of 2006.

In our other geographic market areas, we benefited from increased levels of customer spending driven by high commodity prices. International revenue was a record $99.3 million, primarily due to continued expansion of our rental tools business in markets such as the North Sea, Venezuela, the Middle East and West Africa and well intervention activity in Australia, Egypt and Venezuela. Approximately 55% of our international revenue is derived from the rental tools segment. The remainder is derived from well intervention services such as hydraulic workover, sidetrack drilling and well control services.

Domestically, we aggressively expanded our rentals of drill pipe, ancillary tubulars, handling tools, stabilizers, and drill collars to market areas in Arkansas, Louisiana, Texas, Oklahoma and Wyoming. Toward the end of the year we expanded our well intervention services in these market areas. Drilling rig counts and production-related spending are expected to grow domestically on land, and we believe we can successfully expand our presence in these market areas. As a result, demand should continue at high levels in the markets in which we compete due to the current high level of commodity prices and our customers’ focus on rapidly replacing oil and gas reserves from reservoirs that deliver the highest returns for the least amount of risk.

In the Gulf of Mexico, activity is expected to remain robust. In the deepwater Gulf, large energy producers continue to fund exploration and drilling programs in an effort to locate and produce large reservoirs of oil and gas. The shallow water Gulf is more mature, providing production-enhancement opportunities for smaller operators.

The mature nature of the shallow water Gulf market should benefit our newly constructed derrick barge — which is expected to be available during the third quarter of 2006 — and increase our ability to acquire additional mature properties. We expect decommissioning activity to accelerate as shallow water wells become uneconomical and platforms must be removed. Mature wells often require significant intervention to enhance, extend and maintain production. The costs of this intervention, coupled with the additional risks associated with hurricanes, may lead many energy producers to re-assess the costs and benefits of owning these mature properties.

Well Intervention Segment

The well intervention segment consists of specialized down-hole services, which are both labor and equipment intensive. While our gross margin percentage tends to be fairly consistent, special projects such as well control can directly increase the gross margin percentage.

Revenue and operating income were 15% and 8% higher, respectively, as compared to 2004 despite significant hurricane-related downtime in the Gulf of Mexico and non-recurring, non-cash charges of approximately $4.9 million related to the sale of our oil spill response assets and the reduction in value of our non-hazardous oilfield waste treatment business as a result of our intent to sell the business. The hurricane-related downtime was more than offset by strong Gulf of Mexico activity levels during the first half of the year, especially for services such as coiled tubing, mechanical wireline and electric line services, and improved pricing for many services toward the end of the year. In addition, year-over-year performance improved significantly for well control and hydraulic workover services in non-Gulf of Mexico markets.

Rental Tools Segment

The rental tools segment is capital intensive with high operating margins as a result of relatively low operating costs. The largest fixed cost is typically depreciation as there is little labor associated with our rental tools business. Pricing generally does not fluctuate and financial performance is a function of changes in volume rather than pricing.

Revenue increased 43% and operating income increased 68% over 2004. The biggest increases in revenue and operating income were from the rentals of drill pipe, particularly rentals in international markets, as well as rentals of on-site accommodations and handling tools. Rentals outside the Gulf of Mexico represented more than 60% of this segment’s total revenue in 2005.

Marine Segment

The operating costs of our liftboats are relatively fixed and, therefore, gross margin percentages vary significantly from quarter-to-quarter and year-to-year based on changes in dayrates and utilization levels. As an indication of this segment's performance, our gross margin percentages were 40% in the first quarter, 32% in the second quarter, 36% in the third quarter and 62% in the fourth quarter.

Revenue increased 25% and operating income increased more than 320% over 2004. Liftboat dayrates and utilization steadily increased during the first and second quarters of the year. Activity levels were improving in August prior to Hurricanes Katrina and Rita. Following the storms, dayrates increased to record levels and liftboat utilization averaged approximately 90% during the fourth quarter as our liftboats were used to support our customers' damage assessment and construction projects.

We sold 17 of our smaller liftboats during the second quarter. These liftboats had lower gross profit percentages than our fleet of larger liftboats.

Oil and Gas Segment

Through our subsidiary SPN Resources, LLC, we acquire, manage and decommission mature properties in the shallow waters of the Gulf of Mexico. As of December 31, 2005, we had interests in 32 offshore blocks containing 58 structures and approximately 140 producing wells.

The main objective of this business segment is to provide additional opportunities for our products and services, especially during cyclical and seasonal slower periods. Because of the fixed cost nature of our well intervention services, the incremental cost to work on mature properties is far less than it would be for traditional energy producers. This segment provides work for our services, thereby increasing utilization of our own assets by deploying services on our own properties during periods of downtime.

The lease operating expenses for these types of properties are typically relatively high because of the amount of well intervention service work required to enhance, maintain and extend production for mature properties. The gross operating margin is also a function of oil and gas prices.

Revenues were 113% higher and operating income was 76% higher than 2004. Although we benefited from higher commodity prices and more production as a result of properties we acquired in 2004, approximately 744,000 boe of production was deferred as a result of extensive damage caused by the active hurricane season. We did not suffer any permanent damage to wells, and we expect our production to be fully-restored by the end of the first quarter of 2006.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. Note 1 to our consolidated financial statements contains a description of the accounting policies used in the preparation of our financial statements. We evaluate our estimates on an ongoing basis, including those related to long-lived assets and goodwill, income taxes, allowance for doubtful accounts, self-insurance and oil and gas properties. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances. Actual amounts could differ significantly from these estimates under different assumptions and conditions.

We define a critical accounting policy or estimate as one that is both important to the portrayal of our financial condition and results of operations and requires us to make difficult, subjective or complex judgments or estimates about matters that are uncertain. We believe that the following are the critical accounting policies and estimates used in the preparation of our consolidated financial statements. In addition, there are other items within our consolidated financial statements that require estimates but are not deemed critical as defined in this paragraph.

Long-Lived Assets. We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such asset may not be recoverable. We record impairment losses on long-lived assets, including oil and gas properties, used in operations when the estimated cash flows to be generated by those assets are less than the carrying amount of those items. Our cash flow estimates are based upon, among other things, historical results adjusted to reflect our best estimate of future market rates, utilization levels, operating performance, and with respect to our oil and gas properties, future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas and other factors. Our estimates of cash flows may differ from actual cash flows due to, among other things, changes in economic conditions or changes in an asset’s operating performance. If the sum of the cash flows is less than the carrying value, we recognize an impairment loss, measured as the amount by which the carrying value exceeds the fair value of the asset. The net carrying value of assets not fully recoverable is reduced to fair value. Our estimate of fair value represents our best estimate based on industry trends and reference to market transactions and is subject to variability. The oil and gas industry is cyclical and our estimates of the period over which future cash flows will be generated, as well as the predictability of these cash flows, can have significant impact on the carrying value of these assets and, in periods of prolonged down cycles, may result in impairment charges.

Goodwill. In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the respective assets. If these estimates or their related assumptions adversely change in the future, we may be required to record material impairment charges for these assets not previously recorded. We test goodwill for impairment in accordance with Statement of Financial Accounting Standards No. 142 (FAS No. 142), “Goodwill and Other Intangible Assets.” FAS No. 142 requires that goodwill as well as other intangible assets with indefinite lives no longer be amortized, but instead tested annually for impairment. Our annual testing of goodwill is based on our fair value and carrying value at December 31. We estimate the fair value of each of our reporting units (which are consistent with our reportable segments) using various cash flow and earnings projections. We then compare these fair value estimates to the carrying value of our reporting units. If the fair value of the reporting units exceeds the carrying amount, no impairment loss is recognized. Our estimates of the fair value of these reporting units represent our best estimates based on industry trends and reference to market transactions. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events.

Income Taxes. We provide for income taxes in accordance with Statement of Financial Accounting Standards No. 109 (FAS No. 109), “Accounting for Income Taxes.” This standard takes into account the differences between financial statement treatment and tax treatment of certain transactions. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Our deferred tax calculation requires us to make certain estimates about our future operations. Changes in state, federal and foreign tax laws, as well as changes in our financial condition or the carrying value of existing assets and liabilities, could affect these estimates. The effect of a change in tax rates is recognized as income or expense in the period that includes the enactment date.

Allowance for Doubtful Accounts. We maintain an allowance for doubtful accounts for estimated losses resulting from the inability of some of our customers to make required payments. These estimated allowances are periodically reviewed, on a case by case basis, analyzing the customer’s payment history and information regarding customer’s creditworthiness known to us. In addition, we record a reserve based on the size and age of all receivable balances against which we do not have specific reserves. If the financial condition of our customers was to deteriorate, resulting in their inability to make payments, additional allowances may be required.

Revenue Recognition. We recognize revenue when services or equipment are provided and collectibility is reasonably assured. Services and rentals are generally provided based on fixed or determinable priced purchase orders or contracts with customers. We contract for marine, well intervention and environmental projects either on a day rate or turnkey basis, with a majority of our projects conducted on a day rate basis. Our rental tools are rented on a day rate basis, and revenue from the sale of equipment is recognized when the equipment is shipped. We recognize oil and gas revenue from our interests in producing wells as the commodities are delivered, and the revenue is recorded net of royalties and hedge payments due or inclusive of hedge payments receivable.

Self-Insurance. We self-insure up to certain levels for losses related to workers' compensation, protection and indemnity, general liability, property damage, and group medical. With the recent tightening in the insurance markets, we have elected to retain more risk by increasing our self-insurance. We accrue for these liabilities based on estimates of the ultimate cost of claims incurred as of the balance sheet date. We regularly review our estimates of reported and unreported claims and provide for losses through reserves. We also have an actuary review our estimates for losses related to workers' compensation and group medical on an annual basis. While we believe these estimates are reasonable based on the information available, our financial results could be impacted if litigation trends, claims settlement patterns, health care costs and future inflation rates are different from our estimates. Although we believe adequate reserves have been provided for expected liabilities arising from our self-insured obligations, and we believe that we maintain adequate reinsurance coverage, we cannot assure that such coverage will adequately protect us against liability from all potential consequences.

Oil and Gas Properties. Our subsidiary, SPN Resources, LLC, acquires mature oil and gas properties and assumes the related well abandonment and decommissioning liabilities. We follow the successful efforts method of accounting for our investment in oil and natural gas properties. Under the successful efforts method, the costs of successful exploratory wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip developmental wells, including unsuccessful development wells, are capitalized. Other costs such as geological and geophysical costs and the drilling costs of unsuccessful exploratory wells are expensed. SPN Resources' property purchases are recorded at the value exchanged at closing, combined with an estimate of its proportionate share of the decommissioning liability assumed in the purchase. All capitalized costs are accumulated and recorded separately for each field and allocated to leasehold costs and well costs. Leasehold costs are depleted on a units-of-production basis based on the estimated remaining equivalent proved oil and gas reserves of each field. Well costs are depleted on a units-of-production basis based on the estimated remaining equivalent proved developed oil and gas reserves of each field.

We estimate the third party market value (including an estimated profit) to plug and abandon wells, abandon the pipelines, decommission and remove the platforms and clear the sites, and use that estimate to record our proportionate share of the decommissioning liability. In estimating the decommissioning liabilities, we perform detailed estimating procedures, analysis and engineering studies. Whenever practical, we will utilize the services of our subsidiaries to perform well abandonment and decommissioning work. When these services are performed by our subsidiaries, all recorded intercompany revenues and expenses are eliminated in the consolidated financial statements. The recorded decommissioning liability associated with a specific property is fully extinguished when the property is completely abandoned. The liability is first reduced by all cash expenses incurred to abandon and decommission the property. If the liability exceeds (or is less than) our out-of-pocket costs, the difference is reported as income (or loss) in the period in which the work is performed. We review the adequacy of our decommissioning liability whenever indicators suggest that the estimated cash flows underlying the liability have changed materially. The timing and amounts of these cash flows are subject to changes in the energy industry environment and may result in additional liabilities recorded, which in turn would increase the carrying values of the related properties.

Oil and gas properties are assessed for impairment in value on a field-by-field basis whenever indicators become evident. We use our current estimate of future revenues and operating expenses to test the capitalized costs for impairment. In the event net undiscounted cash flows are less than the carrying value, an impairment loss is recorded based on the present value of expected future net cash flows over the economic lives of the reserves.

Proved Reserve Estimates. Our reserve information is prepared by independent reserve engineers in accordance with guidelines established by the Securities and Exchange Commission and generally accepted accounting principles. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that can not be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. In accordance with the Securities and Exchange Commission's guidelines, we use prices and costs determined on the date of the actual estimate and a 10% discount rate to determine the present value of future net cash flow. Actual prices and costs may vary significantly, and the discount rate may or may not be appropriate based on outside economic conditions.

Derivative Instruments and Hedging Activities. We enter into hedging transactions for our oil production to reduce exposure to the fluctuations in oil prices. Our hedging transactions to date have consisted of financially-settled crude oil swaps and zero-cost collars with a major financial institution. We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Under the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," we are required to record our derivative instruments at fair market value as either assets or liabilities in our consolidated balance sheet. The fair market value is an estimate based on future commodity prices available at the time of the calculation. The fair market value could differ from actual settlements if the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

Comparison of the Results of Operations for the Years Ended December 31, 2005 and 2004

For the year ended December 31, 2005, our revenues were $735.3 million resulting in net income of $67.9 million or $0.85 diluted earnings per share. For the year ended December 31, 2004, revenues were $564.3 million and net income was $35.9 million or $0.47 diluted earnings per share. We experienced higher revenue and gross margin in all our segments, especially our rental tools, oil and gas and well intervention segments as activity levels increased. However, the extraordinarily active hurricane season disrupted most of our activity for several months following Hurricanes Katrina and Rita.

The following table compares our operating results for the years ended December 31, 2005 and 2004. Gross margin is calculated by subtracting cost of services from revenue for each of our four business segments. Oil and gas eliminations represent products and services provided to the oil and gas segment by the Company's three other segments.

	Revenue			Gross Margin				
	2005	2004	Change	2005	%	2004	%	Change
Well Intervention	$339,609	$295,690	$ 43,919	$125,971	37%	$105,832	36%	$ 20,139
Rental Tools	243,536	170,064	73,472	160,974	66%	112,711	66%	48,263
Marine	87,267	69,808	17,459	39,278	45%	20,227	29%	19,051
Oil and Gas	78,911	37,008	41,903	33,107	42%	15,461	42%	17,646
Less: Oil and Gas Elim.	(13,989)	(8,231)	(5,758)	—	—	—	—	—
Total	$735,334	$564,339	$170,995	$359,330	49%	$254,231	45%	$105,099

The following discussion analyzes our operating results on a segment basis.

Well Intervention Segment

Revenue for our well intervention segment was $339.6 million for the year ended December 31, 2005, as compared to $295.7 million for 2004. This segment's gross margin percentage increased slightly to 37% in 2005 from 36% in 2004. We experienced higher revenue for almost all of our services as production-related activity improved in the Gulf of Mexico, particularly for the well control, hydraulic workover, coiled tubing, wireline and field management services. Activity levels declined in the months following Hurricanes Katrina and Rita, but pre-storm demand levels returned near the end of the year.

Rental Tools Segment

Revenue for our rental tools segment for the year ended December 31, 2005 was $243.5 million, a 43% increase over 2004. The gross margin percentage remained unchanged at 66% for the years ended December 31, 2005 and

2004. We experienced significant increases in revenue from our on-site accommodations, drill pipe and accessories and stabilizers. The increases are primarily the result of significant increases in activity in the Gulf of Mexico, as well as our international and domestic expansion efforts. Although our rental tools segment was negatively impacted from Hurricanes Katrina and Rita in August and September of 2005, activity levels surpassed pre-storm levels for most of our rental tools by the end of the year. Our international revenue for the rental tools segment has increased 108% to approximately $53.6 million for the year ended December 31, 2005 from 2004. Our biggest improvements were in the North Sea, Trinidad, Venezuela and Mexico.

Marine Segment

Our marine segment revenue for the year ended December 31, 2005 increased 25% over 2004 to $87.3 million. The gross margin percentage for the year ended December 31, 2005 increased to 45% from 29% for 2004. The year ended December 31, 2005 includes only five months of rental activity from the 105-foot and the 120 to 135-foot class liftboats. These 17 rental liftboats were sold effective June 1, 2005. The increase in revenue is caused by increased utilization of our fleet's remaining larger liftboats at higher dayrates partially offset by fewer liftboats generating revenue for seven months of 2005. The increase in the gross margin percentage is also caused by increased demand and the sale of our lower margin rental liftboats. The fleet's average dayrate increased 47% to approximately $9,223 in the year ended December 31, 2005 from $6,295 in 2004. Increased demand as well as the sale of the smaller liftboats also contributed to the increase in average dayrates. The fleet's average utilization increased to approximately 78% for the year ended December 31, 2005 from 72% in 2004. Our liftboat fleet experienced strong increases in demand and pricing in the fourth quarter as liftboats were needed for the large amount of construction and repair work in the Gulf of Mexico as a result of hurricane damage.

Oil and Gas Segment

Oil and gas revenues were $78.9 million in the year ended December 31, 2005 as compared to $37.0 million in 2004. The increase in revenue is primarily the result of production from South Pass 60, which was acquired in July 2004, and production from West Delta 79/86, which was acquired in December 2004. We also acquired Galveston 241/255 and High Island A-309 in late-July 2005. In the year ended December 31, 2005, production was approximately 1,794,000 boe as compared to approximately 918,000 boe in 2004. The gross margin percentage remained unchanged at 42% for the years ended December 31, 2005 and 2004. The oil and gas segment was affected by significant amounts of curtailed production resulting from the active hurricane seasons the past two years resulting in deferred production as a result of Hurricanes Katrina and Rita in 2005 of approximately 744,000 boe and as a result of Hurricane Ivan in 2004 of approximately 347,000 boe.

Depreciation, Depletion, Amortization and Accretion

Depreciation, depletion, amortization and accretion increased to $89.3 million in the year ended December 31, 2005 from $67.3 million in 2004. The increase is primarily a result of depletion and accretion related to our oil and gas properties from both increased production and acquisitions of oil and gas properties. The increase also results from the depreciation associated with our 2005 and 2004 capital expenditures primarily in the rental tools segment.

General and Administrative

General and administrative expenses increased to $141.0 million for the year ended December 31, 2005 from $110.6 million in 2004. Of this increase, $5.5 million is the result of storm-related costs from Hurricanes Katrina and Rita in the third and fourth quarters of 2005 including $2.1 million in equipment and facility losses and repairs, $2.0 million in relief aid to more than 560 employees affected by the hurricanes and $1.4 million in storm-related payroll expenses, temporary lodging and miscellaneous expenses. The remaining increase was primarily related to increased payroll and bonus expenses, increased insurance costs and expenses as a result of our growth, oil and gas acquisitions and geographic expansion.

Reduction in Value of Assets

During the year ended December 31, 2005, we reduced the value of two of our mature oil and gas properties by approximately $2.1 million, thereby removing the reserve balance associated with these wells. The wells were deemed to be uneconomical to further produce as a result of the estimated costs associated with maintaining production.

Our oil spill containment boom manufacturing facility suffered damage from Hurricane Katrina and experienced difficulty in resuming normal business operations. As a result, we elected not to reopen this manufacturing facility and sell the remaining oil spill containment boom inventory. We reduced the value of the assets of this business (which consist primarily of inventory and property and equipment) by approximately $1.1 million to the estimated net realizable value.

In the first quarter of 2006, we sold our non-hazardous oilfield waste subsidiary, Environmental Treatment Team, L.L.C. (ETT) for approximately $18.7 million in cash. We reduced the net asset value of ETT by $3.8 million in 2005 to its approximate sales price.

Gain on Sale of Liftboats

Effective June 1, 2005, we sold all of our rental liftboats with leg-lengths from 105 feet to 135 feet for $19.8 million in cash (exclusive of costs to sell), which resulted in a gain of $3.5 million.

Comparison of the Results of Operations for the Years Ended December 31, 2004 and 2003

For the year ended December 31, 2004, our revenues were $564.3 million resulting in net income of $35.9 million or $0.47 diluted earnings per share. For the year ended December 31, 2003, revenues were $500.6 million and net income was $30.5 million which includes $2.8 million of pre-tax other income due to the gain from insurance proceeds; diluted earnings per share was $0.41 for the same period. We experienced higher revenues from our rental tools and well intervention segments. We also benefited from oil and gas production following our initial acquisition of properties in the Gulf of Mexico in December 2003.

The following table compares our operating results for the years ended December 31, 2004 and 2003. Gross margin is calculated by subtracting cost of services from revenue for each of our four business segments. Oil and gas eliminations represent products and services provided to the oil and gas segment by the Company’s three other segments.

	Revenue			Gross Margin				
	2004	2003	Change	2004	%	2003	%	Change
Well Intervention	$295,690	$288,152	$ 7,538	$105,832	36%	$ 95,309	33%	$10,523
Rental Tools	170,064	141,362	28,702	112,711	66%	95,243	67%	17,468
Marine	69,808	70,370	(562)	20,227	29%	20,056	29%	171
Oil and Gas	37,008	741	36,267	15,461	42%	410	55%	15,051
Less: Oil and Gas Elim.	(8,231)	—	(8,231)	—	—	—	—	—
Total	$564,339	$500,625	$63,714	$254,231	45%	$211,018	42%	$43,213

The following discussion analyzes our operating results on a segment basis.

Well Intervention Segment

Revenue for our well intervention segment was $295.7 million for the year ended December 31, 2004, as compared to $288.2 million for the same period in 2003. This segment’s gross margin percentage increased to 36% in the year ended December 31, 2004 from 33% in 2003. We experienced increased demand for almost all of our services, and we also benefited by completing various decommissioning projects on our oil and gas properties. The increased revenue was partially offset by the sale of our construction and fabrication assets in August 2003, which had revenue of approximately $19.0 million in 2003. The increase in demand and decommissioning projects contributed to the improvement in the segment’s gross margin percentage.

Rental Tools Segment

Revenue for our rental tools segment for the year ended December 31, 2004 was $170.1 million, a 20% increase over 2003. The increase in this segment's revenue was primarily due to an increased demand for our expanded inventory of downhole rental tool equipment and our continued international expansion, due primarily to the August 2003 acquisition of Premier Oilfield Services. In addition, we benefited from increased bolting, torque and on-site machining work and increased rentals of stabilizers and housing units. The gross margin percentage declined slightly to 66% in the year ended December 31, 2004 from 67% in of 2003 due primarily to a change in the mix of our rental revenue.

Marine Segment

Our marine segment revenue for the year ended December 31, 2004 slightly decreased 1% from 2003 to $69.8 million. The gross margin percentage for the year ended December 31, 2004 remained unchanged at 29%. The fleet's average dayrate decreased slightly to $6,295 in the year ended December 31, 2004 from $6,306 in 2003, but average utilization increased to 72% for the year ended December 31, 2004 from 66% in 2003. Average fleet dayrates entering 2004 were significantly less than the same period a year ago due to lower demand for liftboats. As liftboat utilization increased throughout the year, we began to experience higher rates, particularly in the third and fourth quarters.

Oil and Gas Segment

Oil and gas revenues were $37.0 million and the gross margin percentage was 42% for the year ended December 31, 2004, compared to revenues of $0.7 million and gross margin percentage of 55% for the year ended December 31, 2003. The increase in revenue is due to the fact that our oil and gas segment began in December 2003 and has benefited from the South Pass 60 acquisition completed in July 2004. The segment was negatively impacted by Hurricane Ivan which shut-in or curtailed production from the South Pass 60 field beginning in mid-September 2004 through late December 2004.

Depreciation, Depletion, Amortization and Accretion

Depreciation, depletion, amortization and accretion increased to $67.3 million in the year ended December 31, 2004 from $48.9 million in 2003. The increase is primarily a result of depletion and accretion related to our oil and gas properties. The increase is also the result of our acquisition of Premier Oilfield Services in August 2003 and capital expenditures during 2003 and 2004.

General and Administrative

General and administrative expenses increased to $110.6 million for the year ended December 31, 2004 from $94.8 million in 2003. The increase is primarily the result of our acquisitions, internal growth and international expansion.

Liquidity and Capital Resources

In the year ended December 31, 2005, we generated net cash from operating activities of $158.4 million as compared to $91.3 million in 2004. Our primary liquidity needs are for working capital, capital expenditures, debt service and acquisitions. Our primary sources of liquidity are cash flows from operations and borrowings under our revolving credit facility. We had cash and cash equivalents of $54.5 million at December 31, 2005 compared to $15.3 million at December 31, 2004.

We made $125.2 million of capital expenditures during the year ended December 31, 2005, of which approximately $68.5 million was used to expand and maintain our rental tool equipment inventory. We also made $19.7 million of capital expenditures in our oil and gas segment and $32.8 million of capital expenditures, inclusive of $6.7 million in progress payments made on the crane as noted below and $5.6 million for the purchase of a 200-foot class liftboat which we were previously operating, to expand and maintain the asset base of our well intervention and marine segments. In addition, we made $4.2 million of capital expenditures on construction and improvements to our facilities.

In March 2005, we contracted to construct an 880-ton derrick barge to support our decommissioning operations on the Outer Continental Shelf. The contracts are for the construction of a 350-foot barge and crane for a price of approximately $23 million. This amount does not include any future change orders, barge outfitting or mobilization costs. Progress payments were made on the crane in accordance with the terms set forth in the contract. Letters of credit are due on the barge based on contract milestones. The contract price for the barge will be payable upon its delivery and acceptance. We expect the barge to be available in the Gulf of Mexico late in the third quarter of 2006. We intend to utilize it to remove platforms and structures owned by our subsidiary, SPN Resources, LLC, and compete in the Gulf of Mexico construction market for both installation and removal projects. At December 31, 2005, the total amount of progress payments made on the crane was approximately $6.7 million. We also placed a deposit of approximately $0.6 million on an anchor handling tug for the barge. The remaining balance of approximately $5.3 million is expected to be paid in the first quarter of 2006.

We also paid additional consideration for prior acquisitions of $5.3 million in 2005, all of which were capitalized and accrued during 2004.

We have a bank credit facility consisting of a revolving credit facility of $150 million, with an option to increase it to $250 million. Any balance outstanding on the revolving credit facility is due on October 31, 2008. The credit facility bears interest at a LIBOR rate plus margins that depend on the Company’s leverage ratio. As of February 17, 2006, there was no balance outstanding on this credit facility. Indebtedness under the credit facility is secured by substantially all of the Company’s assets, including the pledge of the stock of the Company’s principal subsidiaries. The credit facility contains customary events of default and requires that the Company satisfy various financial covenants. It also limits the Company’s capital expenditures, its ability to pay dividends or make other distributions, make acquisitions, make changes to the Company’s capital structure, create liens, incur additional indebtedness or assume additional decommissioning liabilities which would require supplemental bonding.

We have $17.4 million outstanding at December 31, 2005 in U. S. Government guaranteed long-term financing under Title XI of the Merchant Marine Act of 1936, which is administered by the Maritime Administration (MARAD), for two 245-foot class liftboats. This debt bears an interest rate of 6.45% per annum and is payable in equal semi-annual installments of $405,000 on every June 3rd and December 3rd through June 3, 2027. Our obligations are secured by mortgages on the two liftboats. This MARAD financing also requires that we comply with certain covenants and restrictions, including the maintenance of minimum net worth and debt-to-equity requirements.

We also have outstanding $200 million of 8 7/8% senior notes due 2011. The indenture governing the senior notes requires semi-annual interest payments on every May 15th and November 15th through the maturity date of May 15, 2011. We may redeem the senior notes during the 12-month period commencing May 15, 2006 at 104.438% of the principal amount redeemed. The indenture governing the senior notes contains certain covenants that, among other things, prevent us from incurring additional debt, paying dividends or making other distributions, unless our ratio of cash flow to interest expense is at least 2.25 to 1, except that we may incur debt in addition to the senior notes in an amount equal to 30% of our net tangible assets, which was approximately $208 million at December 31, 2005. The indenture also contains covenants that restrict our ability to create certain liens, sell assets or enter into certain mergers or acquisitions.

The following table summarizes our contractual cash obligations and commercial commitments at December 31, 2005 (amounts in thousands) for our long-term debt (including estimated interest payments), decommissioning liabilities, operating leases and contractual obligations. The decommissioning liability amounts do not give any effect to our contractual right to receive amounts from third parties, which is approximately $31.5 million, when decommissioning operations are performed. We do not have any other material obligations or commitments.

Description	2006	2007	2008	2009	2010	Thereafter
Long-term debt, including estimated interest payments	$ 19,670	$ 19,617	$ 19,565	$ 19,513	$ 19,461	$ 229,549
Decommissioning liabilities	14,268	26,408	7,294	3,831	13,609	56,499
Operating leases	6,360	4,837	2,723	1,667	1,137	14,181
Derrick barge and tug construction	21,263	—	—	—	—	—
Total	$ 61,561	$ 50,862	$ 29,582	$ 25,011	$ 34,207	$ 300,229

We have no off-balance sheet arrangements other than our potential additional consideration that may be payable as a result of the future operating performances of our acquisitions. At December 31, 2005, the maximum additional consideration payable for our prior acquisitions was approximately $2.4 million. These amounts are not classified as liabilities under generally accepted accounting principles and are not reflected in our financial statements until the amounts are fixed and determinable. When amounts are determined, they are capitalized as part of the purchase price of the related acquisition. We do not have any other financing arrangements that are not required under generally accepted accounting principles to be reflected in our financial statements.

We have identified capital expenditure projects that will require approximately $214 million in 2006, exclusive of any acquisitions for, among other things, geographic expansion, the construction of our derrick barge and anchor handling tug, the refurbishment of a 200-foot class liftboat and reserve additions in our oil and gas segment. We believe that our current working capital, cash generated from our operations and availability under our revolving credit facility will provide sufficient funds for our identified capital projects.

We intend to continue implementing our growth strategy of increasing our scope of services through both internal growth and strategic acquisitions. We expect to continue to make the capital expenditures required to implement our growth strategy in amounts consistent with the amount of cash generated from operating activities, the availability of additional financing and our credit facility. Depending on the size of any future acquisitions, we may require additional equity or debt financing in excess of our current working capital and amounts available under our revolving credit facility.

Hedging Activities

We enter into hedging transactions with major financial institutions to secure a commodity price for a portion of our future production and to reduce our exposure to fluctuations in the price of oil. We do not enter into hedging transactions for trading purposes. Crude oil hedges are settled based on the average of the reported settlement prices for West Texas Intermediate crude on the New York Mercantile Exchange (NYMEX) for each month. We had no natural gas hedges as of December 31, 2005 and 2004. We use financially-settled crude oil swaps and zero-cost collars that provide floor and ceiling prices with varying upside price participation. Our swaps and zero-cost collars are designated and accounted for as cash flow hedges.

With a financially-settled swap, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the hedged price for the transaction, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the hedged price for the transaction. With a zero-cost collar, the counterparty is required to make a payment to us if the settlement price for any settlement period is below the floor price of the collar, and we are required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price for the collar. We recognize the fair value of all derivative instruments as assets or liabilities on the balance sheet. Changes in the fair value of cash flow hedges are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in oil and gas revenues. For the year ended December 31, 2005, hedging settlement payments reduced oil revenues by approximately $10.2 million dollars and gains or losses due to hedge ineffectiveness were not material.

We had the following hedging contracts as of December 31, 2005:

Crude Oil Positions				
Remaining Contract Term	Instrument Type	Strike Price (Bbl)	Volume (Bbls) Daily	Total (Bbls)
01/06 - 8/06	Swap	$ 39.45	1,000 - 1,013	274,388
01/06 - 8/06	Collar	$ 35.00/$45.60	1,000 - 1,013	274,388

Recently Issued Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board revised its Statement of Financial Accounting Standards No. 123 (FAS No. 123R), “Accounting for Stock Based Compensation.” Under FAS No. 123R, companies will be required to recognize as expense the estimated fair value of all share-based payments to employees, including the fair value of employee stock options. This expense will be recognized over the period during which the employee is required to provide service in exchange for the award. Pro forma disclosure of the estimated expense impact of such awards is no longer an alternative to expense recognition in the financial statements. FAS No. 123R is effective for public companies in the first annual period beginning after June 15, 2005, and accordingly, we will adopt the provisions of FAS No. 123R effective January 1, 2006. We anticipate using the modified prospective application transition method, which does not include restatement of prior periods. We expect to record approximately $89,000 of compensation expense in 2006 due to the adoption of FAS No. 123R for share-based awards granted prior to January 1, 2006. We expect the effect of the adoption on future share-based awards to be consistent with the disclosure of pro forma net income and earnings per share as displayed in note 1 of our consolidated financial statements included in Item 8 of this Form 10-K.

In May 2005, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 154 (FAS No. 154), “Accounting Changes and Error Corrections.” This Statement replaces APB Opinion No. 20, “Accounting Changes” and FASB Statement No. 3, “Reporting Accounting Changes in Interim Financial Statements.” FAS No. 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting all changes in accounting principle in the absence of explicit transition requirements of new pronouncements. FAS No. 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risks associated with foreign currency fluctuations and changes in interest rates. A discussion of our market risk exposure in financial instruments follows.

Foreign Currency Exchange Rates

Because we operate in a number of countries throughout the world, we conduct a portion of our business in currencies other than the U.S. dollar. The functional currency for most of our international operations is the U.S. dollar, but a portion of the revenues from our foreign operations is paid in foreign currencies. The effects of foreign currency fluctuations are partly mitigated because local expenses of such foreign operations are also generally denominated in the same currency. We continually monitor the currency exchange risks associated with all contracts not denominated in the U.S. dollar. Any gains or losses associated with such fluctuations have not been material.

We do not hold any foreign currency exchange forward contracts and/or currency options. We have not made use of derivative financial instruments to manage risks associated with existing or anticipated transactions. We do not hold derivatives for trading purposes or use derivatives with complex features. Assets and liabilities of our foreign subsidiaries are translated at current exchange rates, while income and expense are translated at average rates for the period. Translation gains and losses are reported as the foreign currency translation component of accumulated other comprehensive income in stockholders’ equity.

Interest Rates

At December 31, 2005, none of our long-term debt outstanding had variable interest rates, and we had no interest rate risks at that time.

Commodity Price Risk

Our revenue, profitability and future rate of growth partially depends upon the market prices of oil and natural gas. Lower prices may also reduce the amount of oil and gas that can economically be produced.

We use derivative commodity instruments to manage commodity price risks associated with future oil and natural gas production. As of December 31, 2005, we had the following contracts in place:

Crude Oil Positions					
Remaining Contract Term	Instrument Type		Strike Price (Bbl)	Volume (Bbls) Daily	Total (Bbls)
01/06 - 8/06	Swap	$	39.45	1,000 - 1,013	274,388
01/06 - 8/06	Collar	$	35.00/$45.60	1,000 - 1,013	274,388

Our hedged volume as of December 31, 2005 was approximately 50% of our estimated production from proved reserves for the balance of the terms of the contracts. Had these contracts been terminated at December 31, 2005, the estimated loss would have been $6.9 million, net of taxes.

We used a sensitivity analysis technique to evaluate the hypothetical effect that changes in the market value of crude oil would have on the fair value of its existing derivative instruments. Based on the derivative instruments outstanding at December 31, 2005, a 10% increase in the underlying commodity price, increased the net estimated loss associated with the commodity derivative instrument by $1.9 million.

EXHIBIT 99.2

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Superior Energy Services, Inc.:

We have audited the accompanying consolidated balance sheets of Superior Energy Services, Inc. and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2005. In connection with our audit of the consolidated financial statements, we also have audited the accompanying financial statement schedule, "Valuation and Qualifying Accounts," for the years ended December 31, 2005, 2004 and 2003. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Superior Energy Services, Inc. and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

KPMG LLP

New Orleans, Louisiana
March 8, 2006, except as to
Note 14 which is as of
May 11, 2006

SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Consolidated Balance Sheets
December 31, 2005 and 2004
(in thousands, except share data)

	2005	2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 54,457	$ 15,281
Accounts receivable, net of allowance for doubtful accounts of $11,569 and $8,364 at December 31, 2005 and 2004, respectively	196,365	156,235
Income taxes receivable	—	2,694
Current portion of notes receivable	2,364	9,611
Prepaid insurance and other	51,116	28,203
Total current assets	304,302	212,024
Property, plant and equipment, net	440,328	431,334
Oil and gas assets, net, under the successful efforts method of accounting	94,634	83,817
Goodwill, net	220,064	226,593
Notes receivable	29,483	29,131
Investments in affiliates	—	13,552
Other assets, net	8,439	7,462
Total assets	$ 1,097,250	$ 1,003,913
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 42,035	$ 36,496
Accrued expenses	69,926	56,796
Income taxes payable	11,353	—
Fair value of commodity derivative instruments	10,792	2,018
Current portion of decommissioning liabilities	14,268	23,588
Current maturities of long-term debt	810	11,810
Total current liabilities	149,184	130,708
Deferred income taxes	97,987	103,372
Decommissioning liabilities	107,641	90,430
Long-term debt	216,596	244,906
Other long-term liabilities	1,468	618
Stockholders' equity:		
Preferred stock of $0.01 par value. Authorized, 5,000,000 shares; none issued	—	—
Common stock of $0.001 par value. Authorized, 125,000,000 shares; issued and outstanding 79,499,927 and 76,766,303 shares at December 31, 2005 and 2004, respectively	79	77
Additional paid in capital	428,507	398,073
Accumulated other comprehensive income (loss)	(4,916)	2,884
Retained earnings	100,704	32,845
Total stockholders' equity	524,374	433,879
Total liabilities and stockholders' equity	$ 1,097,250	$ 1,003,913

See accompanying notes to consolidated financial statements.

SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Consolidated Statements of Operations
Years Ended December 31, 2005, 2004 and 2003
(in thousands, except per share data)

	2005	2004	2003
Oilfield service and rental revenues	$ 656,423	$ 527,331	$ 499,884
Oil and gas revenues	78,911	37,008	741
Total revenues	735,334	564,339	500,625
Cost of oilfield services and rentals	330,200	288,561	289,276
Cost of oil and gas sales	45,804	21,547	331
Total cost of services, rentals and sales	376,004	310,108	289,607
Depreciation, depletion, amortization and accretion	89,288	67,337	48,853
General and administrative expenses	140,989	110,605	94,822
Reduction in value of assets	6,994	—	—
Gain on sale of liftboats	3,544	—	—
Income from operations	125,603	76,289	67,343
Other income (expense):			
Interest expense, net of amounts capitalized	(21,862)	(22,476)	(22,477)
Interest income	2,201	1,766	209
Other income	—	—	2,762
Equity in earnings of affiliates	1,339	1,329	985
Reduction in value of investment in affiliate	(1,250)	—	—
Income before income taxes	106,031	56,908	48,822
Income taxes	38,172	21,056	18,308
Net income	$ 67,859	$ 35,852	$ 30,514
Basic earnings per share	$ 0.87	$ 0.48	$ 0.41
Diluted earnings per share	$ 0.85	$ 0.47	$ 0.41
Weighted average common shares used in computing earnings per share:			
Basic	78,321	74,896	73,970
Incremental common shares from stock options	1,414	1,004	678
Diluted	79,735	75,900	74,648

See accompanying notes to consolidated financial statements.

SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Consolidated Statements of Changes in Stockholders' Equity
Years Ended December 31, 2005, 2004 and 2003
(in thousands, except share data)

	Preferred stock shares	Preferred stock	Common stock shares	Common stock	Additional paid-in capital	Accumulated other comprehensive income (loss)	Retained earnings (Accumulated deficit)	Total
Balances, December 31, 2002	—	$—	73,819,341	$ 74	$ 368,746	$ 43	$ (33,521)	$ 335,342
Comprehensive income:								
Net income	—	—	—	—	—	—	30,514	30,514
Other comprehensive income - Foreign currency translation adjustment	—	—	—	—	—	221	—	221
Total comprehensive income	—	—	—	—	—	221	30,514	30,735
Exercise of stock options and directors' stock compensation	—	—	279,740	—	1,710	—	—	1,710
Tax benefit from stock options	—	—	—	—	342	—	—	342
Balances, December 31, 2003	—	—	74,099,081	74	370,798	264	(3,007)	368,129
Comprehensive income:								
Net income	—	—	—	—	—	—	35,852	35,852
Other comprehensive income - Changes in fair value of outstanding hedging positions, net of tax	—	—	—	—	—	(1,661)	—	(1,661)
Foreign currency translation adjustment	—	—	—	—	—	4,281	—	4,281
Total comprehensive income	—	—	—	—	—	2,620	35,852	38,472
Stock issued for cash	—	—	11,151,121	12	130,253	—	—	130,265
Purchase and retirement of stock	—	—	(9,696,627)	(10)	(113,428)	—	—	(113,438)
Grant of restricted stock units	—	—	—	—	180	—	—	180
Conversion of restricted stock units	—	—	9,783	—	—	—	—	—
Exercise of stock options and directors' stock compensation	—	—	1,202,945	1	8,295	—	—	8,296
Tax benefit from stock options	—	—	—	—	1,975	—	—	1,975
Balances, December 31, 2004	—	—	76,766,303	77	398,073	2,884	32,845	433,879
Comprehensive income:								
Net income	—	—	—	—	—	—	67,859	67,859
Other comprehensive income - Changes in fair value of outstanding hedging positions, net of tax	—	—	—	—	—	(2,662)	—	(2,662)
Foreign currency translation adjustment	—	—	—	—	—	(5,138)	—	(5,138)
Total comprehensive income	—	—	—	—	—	(7,800)	67,859	60,059
Grant of restricted stock units	—	—	—	—	158	—	—	158
Grant of restricted stock	—	—	24,000	—	178	—	—	178
Exercise of stock options	—	—	2,709,624	2	18,157	—	—	18,159
Tax benefit from stock options	—	—	—	—	11,941	—	—	11,941

Balances, December 31, 2005	—	$—	79,499,927	$ 79	$ 428,507	$(4,916)	$100,704	$ 524,374

See accompanying notes to consolidated financial statements.

SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Consolidated Statements of Cash Flows
Years Ended December 31, 2005, 2004 and 2003
(in thousands)

	2005	2004	2003
Cash flows from operating activities:			
Net income	$ 67,859	$ 35,852	$ 30,514
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	89,288	67,337	48,853
Deferred income taxes	442	15,234	15,183
Reduction in value of assets	6,994	—	—
Equity in income of affiliates	(1,339)	(1,329)	(985)
Reduction in value of investment in affiliate	1,250	—	—
Gain on sale of liftboats	(3,544)	—	—
Other income	—	—	(2,762)
Amortization of debt acquisition costs	1,127	887	1,026
Changes in operating assets and liabilities, net of acquisitions:			
Receivables	(32,095)	(35,279)	104
Other, net	(11,263)	(9,346)	1,773
Accounts payable	5,696	16,142	(1,932)
Accrued expenses	16,599	13,866	2,561
Decommissioning liabilities	(8,772)	(9,157)	—
Income taxes	26,137	(2,876)	5,905
Net cash provided by operating activities	158,379	91,331	100,240
Cash flows from investing activities:			
Payments for capital expenditures	(125,166)	(74,125)	(50,175)
Acquisitions of businesses, net of cash acquired	(6,435)	(24,361)	(14,298)
Acquisitions of oil and gas properties, net of cash acquired	3,686	(10,676)	—
Cash proceeds from sale of liftboats	19,588	—	—
Cash proceeds from sale of affiliate	12,489	—	—
Cash proceeds from insurance settlement	—	—	8,000
Other	(1,097)	—	313
Net cash used in investing activities	(96,935)	(109,162)	(56,160)
Cash flows from financing activities:			
Net payments on revolving credit facility	—	—	(9,250)
Principal payments on long-term debt	(39,310)	(13,713)	(43,089)
Proceeds from long-term debt	—	—	23,000
Payment of debt acquisition costs	(439)	(60)	(479)
Proceeds from exercise of stock options	18,161	10,271	2,052
Proceeds from issuance of stock	—	130,265	—
Purchase and retirement of stock	—	(113,438)	—
Net cash provided by (used in) financing activities	(21,588)	13,325	(27,766)
Effect of exchange rate changes in cash	(680)	(7)	—
Net increase (decrease) in cash and cash equivalents	39,176	(4,513)	16,314
Cash and cash equivalents at beginning of year	15,281	19,794	3,480
Cash and cash equivalents at end of year	$ 54,457	$ 15,281	$ 19,794

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies

(a) Basis of Presentation

The consolidated financial statements include the accounts of Superior Energy Services, Inc. and subsidiaries (the Company). All significant intercompany accounts and transactions are eliminated in consolidation. Certain previously reported amounts have been reclassified to conform to the 2005 presentation.

(b) Business

The Company is a leading provider of specialized oilfield services and equipment focusing on serving the production-related needs of oil and gas companies in the Gulf of Mexico and the drilling-related needs of oil and gas companies throughout the world. The Company provides most of the services, tools and liftboats necessary to maintain, enhance and extend offshore producing wells, as well as plug and abandonment services at the end of their life cycle.

In December 2003, the Company began acquiring oil and gas properties in order to provide additional opportunities for its well intervention and platform management operations in the Gulf of Mexico. The Company intends to continue to acquire mature properties from its customers with modest amounts of estimated remaining productive life, to provide all of its services to the properties to produce any remaining proven oil and gas reserves and to decommission and abandon the properties.

(c) Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(d) Major Customers and Concentration of Credit Risk

A majority of the Company's business is conducted with major and independent oil and gas exploration companies. The Company continually evaluates the financial strength of its customers and provides allowances for probable credit losses when deemed necessary but does not require collateral to support the customer receivables.

The market for the Company's services and products is primarily the offshore oil and gas industry in the Gulf of Mexico. Oil and gas companies make capital expenditures on exploration, drilling and production operations offshore. The level of these expenditures has been characterized by significant volatility.

The Company derives a significant amount of revenue from a small number of major and independent oil and gas companies. In 2005, Shell accounted for approximately 10% of total revenue, primarily related to our oil and gas and rental tools segments. No customer accounted for more than 10% of the Company's total revenue in 2004. In 2003, one customer accounted for approximately 11% of its total revenue, primarily in the well intervention segment. The Company's inability to continue to perform services for a number of large existing customers, if not offset by sales to new or existing customers, could have a material adverse effect on the Company's business and financial condition.

(e) Cash Equivalents

The Company considers all short-term deposits with a maturity of ninety days or less to be cash equivalents.

(f) Accounts Receivable and Allowances

Trade accounts receivables are recorded at the invoiced amount and do not bear interest. The Company maintains allowances for bad debts and various other adjustments. The allowance for doubtful accounts is based on the Company's best estimate of the amount of probable uncollectible amounts in existing accounts receivable. The Company determines the allowances based on historical write-off experience and specific identification.

(g) Prepaid Insurance and Other

Prepaid insurance and other includes approximately $23.9 million and $11.1 million in insurance receivables at December 31, 2005 and 2004, respectively. The December 31, 2005 balance is primarily due to the impact of Hurricanes Katrina and Rita on our oil and gas properties, as well as our buildings and equipment. The December 31, 2004 balance is primarily related to the impact of Hurricane Ivan on our oil and gas properties. The insurance deductibles on Hurricanes Katrina and Rita of approximately $1 million were expensed during 2005. All amounts not expected to be reimbursed by insurance are expensed as incurred.

(h) Property, Plant and Equipment

Property, plant and equipment are stated at cost. With the exception of the Company's liftboats and oil and gas assets, depreciation is computed using the straight-line method over the estimated useful lives of the related assets as follows:

Buildings and improvements	5 to 40 years
Marine vessels and equipment	5 to 25 years
Machinery and equipment	5 to 20 years
Automobiles, trucks, tractors and trailers	2 to 10 years
Furniture and fixtures	3 to 10 years

Marine vessels and oil and gas producing assets are depreciated or depleted based on utilization or units-of-production, because depreciation and depletion occur primarily through use rather than through the passage of time. Units of production depreciation on marine vessels is subject to a minimum amount of depreciation each year.

The Company capitalizes interest on borrowings used to finance the cost of major capital projects during the active construction period. Capitalized interest is added to the cost of the underlying assets and is amortized over the useful lives of the assets. For 2005 and 2003, the Company capitalized approximately $456,000 and $87,000, respectively, of interest for various capital projects. There was no interest capitalized during 2004.

Long-lived assets and certain identifiable intangibles are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to future net cash flows expected to be generated by the assets. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value. Assets are grouped by subsidiary or division for the impairment testing, except for liftboats which are grouped together by similar leg-lengths. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

The Company's subsidiary, SPN Resources, LLC, acquires oil and natural gas properties and assumes the related decommissioning liabilities. The Company follows the successful efforts method of accounting for its investment in oil and natural gas properties. Under the successful efforts method, the costs of successful exploratory wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip developmental wells, including unsuccessful development wells are capitalized. Other costs such as geological and geophysical costs and the drilling costs of unsuccessful exploratory wells are expensed. SPN Resources' property purchases are recorded at the value exchanged at closing, combined with an estimate of its proportionate share of the decommissioning liability assumed in the purchase. All capitalized costs are accumulated and recorded separately for each field and allocated to leasehold costs and well costs. Leasehold costs are depleted on a units-of-production basis based on the estimated remaining equivalent proved oil and gas reserves of each field. Well costs are depleted on a units-of-production basis based on the estimated remaining equivalent proved developed oil and gas reserves of each field.

The Company adopted Financial Accounting Standards Board Staff Position FAS 19-1, "Accounting for Suspended Well Costs" (FSP 19-1) effective July 1, 2005. FSP 19-1 amended Statement of Financial Accounting Standards No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" (Statement 19), to permit the continued capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company has not, and does not currently drill in the areas that require major capital expenditures before production can begin. The Company evaluated all existing capitalized well costs under the provisions of FSP-19-1 and determined there was no impact to the Company's consolidated financial statements.

Oil and gas properties are assessed for impairment in value on a field-by-field basis whenever indicators become evident. The Company uses its current estimate of future revenues and operating expenses to test the capitalized costs for impairment. In the event net undiscounted cash flows are less than the carrying value, an impairment loss is recorded based on the present value of expected future net cash flows over the economic lives of the reserves.

(i) Goodwill

The Company accounts for goodwill and other intangible assets in accordance with Statement of Financial Accounting Standards No. 142 (FAS No. 142), "Goodwill and Other Intangible Assets." FAS No. 142 requires that goodwill as well as other intangible assets with indefinite lives no longer be amortized, but instead tested annually for impairment. To test for impairment, the Company identifies its reporting units (which are consistent with the Company's reportable segments) and determines the carrying value of each reporting unit by assigning the assets and liabilities, including goodwill and intangible assets, to the reporting units. The Company then estimates the fair value of each reporting unit and compares it to the reporting unit's carrying value. Based on this test, the fair value of the reporting units exceeded the carrying amount, and the second step of the impairment test is not required. No impairment loss was recognized in the years ended December 31, 2005, 2004 or 2003 under this method. However, the Company reduced the value of goodwill by approximately $3.8 million to approximate the sales price of its subsidiary, Environmental Treatment Team, L.L.C., (ETT), which was sold in the first quarter of 2006 (see note 3). Goodwill also decreased by approximately $2.7 million in 2005 as the result of changes in foreign currency exchange rates. Accumulated amortization of goodwill is $9.2 million at December 31, 2005 and 2004.

(j) Notes Receivable

Notes receivable consist primarily of commitments from the sellers of oil and gas properties towards the abandonment of the acquired properties. Pursuant to the agreement between the Company and a seller, the Company will invoice the seller agreed upon amounts during the course of decommissioning (abandonment and structure removal). These receivables are recorded at present value, and the related discounts are amortized to interest income, based on the expected timing of the decommissionings.

(k) Other Assets

Other assets consist primarily of debt acquisition costs and deferred compensation plan assets. Debt acquisition costs are being amortized over the term of the related debt, which is from three to twenty-five years. The amortization of debt acquisition costs, which is classified as interest expense, was approximately $1,127,000, $887,000 and $1,026,000 for the years ended December 31, 2005, 2004 and 2003, respectively. Accumulated amortization of other assets is approximately $6,062,000 and $4,604,000 at December 31, 2005 and 2004, respectively.

(l) Decommissioning Liability

The Company records estimated future decommissioning liabilities related to its oil and gas producing properties pursuant to the provisions of Statement of Financial Accounting Standards No. 143 (FAS No. 143), "Accounting for Asset Retirement Obligations." FAS No. 143 requires entities to record the fair value of a liability at estimated present value for an asset retirement obligation (decommissioning liabilities) in the period in which it is incurred with a corresponding increase in the carrying amount of the related long-lived asset. Subsequent to initial measurement, the decommissioning liability is required to be accreted each period to present value. The Company's decommissioning liabilities consist of costs related to the plugging of wells, the removal of facilities and equipment and site restoration on oil and gas properties.

The Company estimates the cost that would be incurred if it contracted an unaffiliated third party to plug and abandon wells, abandon the pipelines, decommission and remove the platforms and pipelines and clear the sites of its oil and gas properties, and uses that estimate to record its proportionate share of the decommissioning liability. In estimating the decommissioning liability, the Company performs detailed estimating procedures, analysis and engineering studies. Whenever practical, the Company utilizes its own equipment and labor services to perform well abandonment and decommissioning work. When the Company performs these services, all recorded intercompany revenues are eliminated in the consolidated financial statements. The recorded decommissioning liability associated with a specific property is fully extinguished when the property is abandoned. The recorded liability is first reduced by all cash expenses incurred to abandon and decommission the property. If the recorded liability exceeds (or is less than) the Company's out-of-pocket costs, then the difference is reported as income (or loss) within revenue during the period in which the work is performed. The Company reviews the adequacy of its decommissioning liability whenever indicators suggest that the estimated cash flows needed to satisfy the liability have changed materially. The timing and amounts of these cash flows are estimates, and changes to these estimates may result in additional (or decreased) liabilities recorded, which in turn would increase (or decrease) the carrying values of the related oil and gas properties.

SPN Resources purchased its first oil and gas properties and assumed the related decommissioning liabilities in December 2003, thus comparable data for the year ended December 31, 2003 is not material. The following table summarizes the activity for the Company's decommissioning liability for the twelve months ended December 31, 2005 and 2004 (amounts in thousands):

	Year Ended December 31,	
	2005	2004
Decommissioning liabilities, at beginning of period	$114,018	$ 38,853
Liabilities acquired and incurred	11,494	83,021
Liabilities settled	(8,772)	(9,157)
Accretion	4,476	2,836
Revision in estimated liabilities	693	(1,535)
Total	121,909	114,018
Current portion of decommissioning liabilities	14,268	23,588
Decommissioning liabilities, at end of period	$107,641	$ 90,430

(m) Revenue Recognition

Revenue is recognized when services or equipment are provided. The Company contracts for marine, well intervention and environmental projects either on a day rate or turnkey basis, with a majority of its projects conducted on a day rate basis. The Company's rental tools are rented on a day rate basis, and revenue from the sale of equipment is recognized when the equipment is shipped. Reimbursements from customers for the cost of rental tools that are damaged or lost down-hole are reflected as revenue at the time of the incident. The Company recognizes oil and gas revenue from its interests in producing wells as oil and natural gas is produced and sold from those wells.

(n) Income Taxes

The Company provides for income taxes in accordance with Statement of Financial Accounting Standards No. 109 (FAS No. 109), "Accounting for Income Taxes." FAS No. 109 requires an asset and liability approach for financial accounting and reporting for income taxes. Deferred income taxes reflect the impact of temporary differences between amounts of assets and liabilities for financial reporting purposes and such amounts as measured by tax laws.

(o) Earnings per Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed in the same manner as basic earnings per share except that the denominator is increased to include the number of additional common shares that could have been outstanding assuming the exercise of stock options and restricted stock units and the potential shares that would have a dilutive effect on earnings per share.

(p) Financial Instruments

The fair value of the Company's financial instruments of cash, accounts receivable and current maturities of long-term debt approximates their carrying amounts. The fair value of the Company's long-term debt is approximately $227 million at December 31, 2005.

(q) Foreign Currency Translation

Assets and liabilities of the Company's foreign subsidiaries are translated at current exchange rates, while income and expenses are translated at average rates for the period. Translation gains and losses are reported as the foreign currency translation component of accumulated other comprehensive income in stockholders' equity.

(r) Stock Based Compensation

The Company accounts for its stock based compensation under the principles prescribed by the Accounting Principles Board's Opinion No. 25 (Opinion No. 25), "Accounting for Stock Issued to Employees" However, Statement of Financial Accounting Standards No. 123 (FAS No. 123), "Accounting for Stock-Based Compensation" permits the continued use of the intrinsic-value based method prescribed by Opinion No. 25 but requires additional disclosures, including pro forma calculations of earnings and net earnings per share as if the fair value method of accounting prescribed by FAS No. 123 had been applied. No stock based compensation costs from stock options are reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Stock compensation costs from the grant of restricted stock units and restricted stock are expensed as incurred (see note 11). The pro forma data presented below is not representative of the effects on reported amounts for future years (amounts are in thousands, except per share amounts).

	2005	2004	2003
Net income, as reported	$67,859	$35,852	$30,514
Stock-based employee compensation expense, net of tax	(4,421)	(6,999)	(2,671)
Pro forma net income	$63,438	$28,853	$27,843
Basic earnings per share:			
Earnings, as reported	$ 0.87	$ 0.48	$ 0.41
Stock-based employee compensation expense, net of tax	(0.06)	(0.09)	(0.04)
Pro forma earnings per share	$ 0.81	$ 0.39	$ 0.37
Diluted earnings per share:			
Earnings, as reported	$ 0.85	$ 0.47	$ 0.41
Stock-based employee compensation expense, net of tax	(0.06)	(0.09)	(0.04)
Pro forma earnings per share	$ 0.79	$ 0.38	$ 0.37
Black-Scholes option pricing model assumptions:			
Risk free interest rate	3.85%	4.28%	2.65%
Expected life (years)	6	5	3
Volatility	38.91%	65.22%	58.61%
Dividend yield	—	—	—

In December 2004, the Financial Accounting Standards Board revised its Statement of Financial Accounting Standards No. 123 (FAS No. 123R), "Accounting for Stock Based Compensation." Under FAS No. 123R, companies will be required to recognize as expense the estimated fair value of all share-based payments to employees, including the fair value of employee stock options. This expense will be recognized over the period during which the employee is required to provide service in exchange for the award. Pro forma disclosure of the estimated expense impact of such awards is no longer an alternative to expense recognition in the financial statements. FAS No. 123R is effective for public companies in the first annual period beginning after June 15, 2005, and accordingly, the Company will adopt the provisions of FAS No. 123R effective January 1, 2006. The Company anticipates using the modified prospective application transition method, which does not include restatement of prior periods. The Company expects to record approximately $89,000 of compensation expense in 2006 due to the adoption of FAS No. 123R for share-based awards granted prior to January 1, 2006. The Company expects the effect of the adoption on future awards to be consistent with the disclosure of pro forma net income and earnings per share as displayed above.

Long-Term Incentive Plan

In May 2005, the Company's stockholders approved the 2005 Stock Incentive Plan ("2005 Incentive Plan") to provide long-term incentives to its officers, key employees, consultants and advisers ("Eligible Participants"). Under the 2005 Incentive Plan, the Company may grant incentive stock options, non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, other stock-based awards or any combination thereof to Eligible Participants for up to 4,000,000 shares of common stock. The Compensation Committee of the Board of Directors establishes the term and the exercise price of any stock options granted under the 2005 Incentive Plan, provided the exercise price may not be less than the fair market value of the common stock on the date of grant. On June 24, 2005, the Compensation Committee awarded approximately 864,000 non-qualified stock options to Eligible Participants under the 2005 Incentive Plan. This grant was fully-vested by December 31, 2005.

On June 24, 2005, the Compensation Committee also awarded approximately 32,000 performance share units ("Units"). The performance period for the Units runs from January 1, 2005 through December 31, 2007. The two performance measures applicable to all participants are the Company's return on invested capital and total shareholder return relative to those of the Company's pre-defined "peer group." Participants can earn from $0 to $200 per Unit, as determined by the Company's achievement of the performance measures. The Units provide for settlement in cash or up to 50% in equivalent value in Company common stock, if the participant has met specified continued service requirements. The Company's compensation expense related to the grant of the Units was approximately $1.1 million, which is reflected in general and administrative expenses, for the year ended December 31, 2005.

Subsequent event

On February 23, 2006, the Compensation Committee granted long-term incentive awards to each of the Company's named executive officers and other key employees of the Company under its stockholder approved 2005 Stock Incentive Plan. These awards consisted of approximately 213,000 non-qualified stock options, 104,000 shares of restricted stock and 34,000 performance share units ("Units").

The non-qualified options will be exercisable in equal installments on the anniversary of the date of the grant for three consecutive years, and will expire on the tenth anniversary of the date grant. Holders of the shares of restricted stock are entitled to all rights of a shareholder of the Company with respect to the restricted stock, including the right to vote the shares and receive all dividends and other distributions declared thereon. The shares of restricted stock will be exercisable in equal installments on the anniversary date of the grant for three consecutive years. The performance period for the Units runs from January 1, 2006 through December 31, 2008. The two performance measures applicable to all participants are the Company's return on invested capital and total shareholder return relative to those of the Company's pre-defined "peer group." Participants can earn from $0 to $200 per Unit, as determined by the Company's achievement of the performance measures. The Units provide for settlement in cash or up to 50% in equivalent value in Company common stock, if the participant has met specified continued service requirements.

(s) Hedging Activities

The Company enters into hedging transactions with major financial institutions to secure a commodity price for a portion of future production and to reduce the Company's exposure to fluctuations in the price of oil. The Company does not enter into hedging transactions for trading purposes. Crude oil hedges are settled based on the average of the reported settlement prices for West Texas Intermediate crude on the New York Mercantile Exchange (NYMEX) for each month. The Company had no natural gas hedges as of December 31, 2005 and 2004. The Company uses financially-settled crude oil swaps and zero-cost collars that provide floor and ceiling prices. The Company's swaps and zero-cost collars are designated and accounted for as cash flow hedges.

With a financially-settled swap, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the hedged price for the transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the hedged price for the transaction. With a zero-cost collar, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price of the collar, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the cap price for the collar. The Company recognizes the fair value of all derivative instruments as assets or liabilities on the balance sheet. Changes in the fair value of cash flow hedges are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is settled and recorded in oil and gas revenue. For the years ended December 31, 2005 and 2004, hedging settlement payments reduced oil revenues by approximately $10.2 million and $1.6 million, respectively. The Company recorded no gains or losses due to hedge ineffectiveness, but any gains or losses resulting from hedge ineffectiveness would be recorded in revenue.

The Company had the following hedging contracts as of December 31, 2005:

Crude Oil Positions				
Remaining Contract Term	Instrument Type	Strike Price (Bbl)	Volume (Bbls) Daily	Total (Bbls)
01/06 - 8/06	Swap	$ 39.45	1,000 - 1,013	274,388
01/06 - 8/06	Collar	$ 35.00/$45.60	1,000 - 1,013	274,388

Based upon current market prices, the Company expects to transfer approximately $6.9 million of net deferred losses in accumulated other comprehensive loss as of December 31, 2005 to earnings during the next twelve months when the forecasted transactions actually occur.

(t) Other Comprehensive Income

The following table reconciles the change in accumulated other comprehensive income for the years ended December 31, 2005 and 2004 (amounts in thousands):

	Year Ended December 31, 2005	Year Ended December 31, 2004
Accumulated other comprehensive income, December 31, 2004 and 2003, respectively	$ 2,884	$ 264
Other comprehensive income (loss), net of tax:		
Hedging activities:		
Reclassification adjustment for settled contracts, net of tax of $3,656 in 2005 and $576 in 2004	6,499	981
Changes in fair value of outstanding hedging positions, net of tax of ($6,545) in 2005 and ($1,552) in 2004	(11,637)	(2,642)
Foreign currency translation adjustment	(2,662)	4,281
Total other comprehensive income	(7,800)	2,620
Accumulated other comprehensive income, December 31, 2005 and 2004, respectively	$ (4,916)	$ 2,884

(2) Supplemental Cash Flow Information

The following table includes the Company's supplemental cash flow information for the years ended December 31, 2005, 2004 and 2003 (amounts in thousands):

	2005	2004	2003
Cash paid for interest	$ 21,152	$ 23,320	$ 23,633
Cash paid (received) for income taxes	$ 10,789	$ 7,360	$ (4,125)
Details of business acquisitions:			
Fair value of assets	$ 6,627	$ 25,614	$ 51,103
Fair value of liabilities	(31)	(1,158)	(35,270)
Cash paid	6,596	24,456	15,833
Less cash acquired	(163)	(95)	(1,535)
Net cash paid for acquisitions	$ 6,433	$ 24,361	$ 14,298
Details of oil and gas property acquisitions:			
Fair value of assets	$ 11,494	$ 97,792	$ 39,509
Fair value of liabilities	(11,494)	(82,107)	(39,509)
Cash paid	—	15,685	—
Less cash acquired	(3,686)	(5,009)	—
Net cash paid (received) for acquisitions	$ (3,686)	$ 10,676	$ —
Non-cash investing activity:			
Receivable from sale of affiliate	$ 1,305	$ —	$ —
Additional consideration payable on acquisitions	$ —	$ 5,272	$ 11,263
Note receivable from asset disposition	$ —	$ —	$ 938

(3) Reduction in Value of Assets

During the year ended December 31, 2005, the Company reduced the value of two of its mature oil and gas properties by approximately $2.1 million due to well issues affecting production rates and operating costs. The Company deemed it to be uneconomical to perform additional production enhancement work to maintain production at these properties.

Also during the year ended December 31, 2005, the Company's oil spill containment boom manufacturing facility suffered damage from Hurricane Katrina and experienced difficulty in resuming normal business operations. As a result, the Company elected not to reopen this manufacturing facility and sell the remaining oil spill containment boom inventory. The value of the assets of this business (which consist primarily of inventory and property and equipment) were reduced by approximately $1.1 million to their estimated net realizable value.

In the first quarter of 2006, the Company sold its subsidiary ETT for approximately $18.7 million in cash. The Company reduced the net asset value of ETT by $3.8 million in 2005 to the approximate sales price of the subsidiary. For the years ended December 31, 2005, 2004 and 2003, revenue from ETT was approximately $27.7 million, $24.0 million and $21.7 million, respectively, and operating losses were approximately $5.1 million (inclusive of the $3.8 million loss), $2.1 million and $1.2 million, respectively.

(4) Gain on Sale of Liftboats

Effective June 1, 2005, the Company sold 17 of its rental liftboats with leg-lengths from 105 feet to 135 feet for $19.6 million in cash (net of costs to sell). This constituted all of the Company's rental fleet of liftboats with leg-lengths of 135 feet or less. The Company recorded a gain of $3.5 million as a result of this transaction.

(5) Other Income

As the result of a tropical storm, one of the Company's 200-foot class liftboats sank in the Gulf of Mexico on June 30, 2003. The vessel was declared a total loss and the Company received $8 million of insurance proceeds for the vessel. As a result, the Company recorded a gain from the insurance proceeds of $2.8 million, which is included in other income in the year ended December 31, 2003.

(6) Acquisitions and Dispositions

In July 2005, the Company acquired a business for an aggregate purchase price of approximately $1.3 million in cash consideration in order to geographically expand the snubbing services offered by its well intervention segment. Additional consideration, if any, will be based upon the average earnings before interest, income taxes, depreciation and amortization expense (EBITDA) over a three-year period, and will not exceed $0.4 million. This acquisition has been accounted for as a purchase and the acquired assets and liabilities have been valued at their estimated fair value. The purchase price preliminarily allocated to net assets was approximately $1.3 million, and no goodwill was recorded. The results of operations have been included from the acquisition date. The pro forma effect of operations of the acquisition when included as of the beginning of the periods presented was not material to the Consolidated Statements of Operations of the Company.

Also in July 2005, the Company's subsidiary, SPN Resources, LLC, acquired additional oil and gas properties at Galveston 241/255 and High Island A-309 through the acquisition of three offshore Gulf of Mexico leases. Under the terms of the transaction, the Company acquired the properties and assumed the related decommissioning liabilities. The Company received $3.7 million in cash and will invoice the sellers at agreed upon prices as the decommissioning activities (abandonment and structure removal) are completed. The Company preliminarily recorded notes receivable of approximately $2.4 million, decommissioning liabilities of $11.5 million and oil and gas producing assets were recorded at their estimated fair value of $5.4 million. The pro forma effect of operations of the acquisition when included as of the beginning of the periods presented was not material to the Consolidated Statements of Operations of the Company.

In 2004, the Company's wholly-owned subsidiary, SPN Resources, LLC, acquired additional oil and gas properties through the acquisition of interests in 19 offshore Gulf of Mexico leases. Under the terms of the transactions, the Company acquired the properties and assumed the decommissioning liabilities. In the aggregate, the Company paid $10.7 million cash, net of amounts received. The Company recorded decommissioning liabilities of approximately $83.0 million and notes and other receivables of approximately $12.5 million, and oil and gas producing assets were recorded at their estimated fair value of approximately $81.2 million.

In 2004, the Company acquired two businesses for an aggregate of $2.8 million in cash consideration in order to enhance the products and services offered by its rental tools segment and well intervention segment. These acquisitions were accounted for as purchases. The estimated fair value of the net assets acquired was approximately $1.0 million in the aggregate, and the excess purchase price over the fair value of net assets of approximately $1.8 million was allocated to goodwill. The results of operations have been included from the respective acquisition dates.

Most of the Company's business acquisitions have involved additional contingent consideration based upon a multiple of the acquired companies' respective average EBITDA over a three-year period from the respective date of acquisition. As of December 31, 2005, the maximum additional consideration payable for the Company's prior acquisitions was approximately $2.4 million, and will be determined and payable through 2008. These amounts are not classified as liabilities under generally accepted accounting principles and are not reflected in the Company's financial statements until the amounts are fixed and determinable. The Company does not have any other financing arrangements that are not required under generally accepted accounting principles to be reflected in its financial statements. When the amounts are determined, they are capitalized as part of the purchase price of the related acquisition. In January 2005, the Company paid additional consideration of $5.3 million as a result of a prior acquisition, which had been capitalized and accrued in 2004.

(7) Property, Plant and Equipment

A summary of property, plant and equipment at December 31, 2005 and 2004 (in thousands) is as follows:

	2005	2004
Buildings and improvements	$ 58,567	$ 57,624
Marine vessels and equipment	177,047	193,321
Machinery and equipment	394,582	342,700
Automobiles, trucks, tractors and trailers	9,428	10,248
Furniture and fixtures	13,440	11,944
Construction-in-progress	19,054	2,498
Land	6,581	6,037
	678,699	624,372
Accumulated depreciation	(238,371)	(193,038)
Property, plant and equipment, net	$ 440,328	$ 431,334
Oil and gas assets	119,986	91,104
Accumulated depletion	(25,352)	(7,287)
Oil and gas assets, net, under the successful efforts method of accounting	$ 94,634	$ 83,817

Amounts of property, plant and equipment leased to third parties at December 31, 2005 and 2004 were not material. Depreciation expense (excluding depletion, amortization and accretion) was approximately $68.6 million, $57.1 million and $48.5 million for the years ended December 31, 2005, 2004 and 2003, respectively.

(8) Investments in Affiliates

On November 2, 2005, the Company's investment in affiliate sold substantially all of its assets. The Company received $12.5 million as a result of the sale and has recorded receivables of approximately $1.3 million for the remaining proceeds to be distributed. The Company reduced the value of this investment by approximately $1.3 million during 2005 in anticipation of this sale.

(9) Long-Term Debt

The Company's long-term debt as of December 31, 2005 and 2004 consisted of the following (in thousands):

	2005	2004
Senior Notes — interest payable semiannually at 8.875%, due May 2011	$ 200,000	$ 200,000
Term Loans — repaid in November 2005	—	38,500
Revolver — interest payable monthly at floating rate, due in October 2008	—	—
U.S. Government guaranteed long-term financing — interest payable semianually at 6.45%, due in semiannual installments through June 2027	17,406	18,216
	217,406	256,716
Less current portion	810	11,810
Long-term debt	$ 216,596	$ 244,906

Effective October 31, 2005, the Company amended its bank credit facility to convert the existing term loans and revolving credit facility into a single $150 million revolving credit facility, with an option to increase it to $250 million. Any balance outstanding on the revolving credit facility is due on October 31, 2008. At December 31, 2005, the Company had no balance on this bank credit facility. The credit facility bears interest at a LIBOR rate plus margins that depend on the Company's leverage ratio. Indebtedness under the credit facility is secured by substantially all of the Company's assets, including the pledge of the stock of the Company's principal subsidiaries. The credit facility contains customary events of default and requires that the Company satisfy various financial covenants. It also limits the Company's capital expenditures, its ability to pay dividends or make other distributions, make acquisitions, make changes to the Company's capital structure, create liens, incur additional indebtedness or assume additional decommissioning liabilities. The Company also has letters of credit outstanding of approximately $18.6 million at December 31, 2005, which reduce the borrowing availability under its revolving credit facility. At December 31, 2005, the Company was in compliance with all such covenants. The Company wrote-off debt acquisition costs of approximately $224,000 due to the repayment of its term loans. This write-off is included in interest expense in 2005.

The Company has $17.4 million outstanding in U. S. Government guaranteed long-term financing under Title XI of the Merchant Marine Act of 1936, which is administered by the Maritime Administration (MARAD) for two 245-foot class liftboats. The debt bears an interest rate of 6.45% per annum and is payable in equal semi-annual installments of $405,000, which began December 3, 2002, and matures on June 3, 2027. The Company's obligations are secured by mortgages on the two liftboats. In accordance with the agreement, the Company is required to comply with certain covenants and restrictions, including the maintenance of minimum net worth and debt-to-equity requirements. This long-term financing ranks equally with the bank credit facility as both are secured by unique assets.

The Company also has outstanding $200 million of 8 7/8% unsecured senior notes due 2011. The indenture governing the notes requires semi-annual interest payments, on every November 15th and May 15th through the maturity date of May 15, 2011. The Company may redeem the notes during the 12-month period commencing May 15, 2006 at 104.438% of the principal amount redeemed. The indenture governing the senior notes contains certain covenants that, among other things, prevent the Company from incurring additional debt, paying dividends or making other distributions, unless its ratio of cash flow to interest expense is at least 2.25 to 1, except that the Company may incur debt in addition to the senior notes in an amount equal to 30% of its net tangible assets as defined, which was approximately $208 million at December 31, 2005. The indenture also contains covenants that restrict the Company's ability to create certain liens, sell assets, or enter into certain mergers or acquisitions.

Annual maturities of long-term debt for each of the five fiscal years following December 31, 2005 are as follows (in thousands):

2006	$ 810
2007	810
2008	810
2009	810
2010	810
Thereafter	213,356
Total	$ 217,406

(10) Income Taxes

The components of income tax expense (benefit) for the years ended December 31, 2005, 2004 and 2003 are as follows (in thousands):

	2005	2004	2003
Current			
Federal	$ 30,745	$ 87	$ 515
State	897	415	245
Foreign	6,087	5,320	2,365
	37,729	5,822	3,125
Deferred			
Federal	1,895	17,569	14,561
State	94	105	1,220
Foreign	(1,547)	(2,440)	(598)
	442	15,234	15,183
	$ 38,171	$ 21,056	$ 18,308

Income tax expense differs from the amounts computed by applying the U.S. Federal income tax rate of 35% to income before income taxes as follows (in thousands):

	2005	2004	2003
Computed expected tax expense	$ 37,111	$ 19,918	$ 17,088
Increase resulting from:			
State and foreign income taxes	241	178	478
Other	819	960	742
Income tax expense	$ 38,171	$ 21,056	$ 18,308

The significant components of deferred income taxes at December 31, 2005 and 2004 are as follows (in thousands):

	2005	2004
Deferred tax assets:		
Allowance for doubtful accounts	$ 1,793	$ 776
Alternative minimum tax credit and net operating loss carryforward	8,198	12,358
Decommissioning liability	45,106	42,187
Other	9,476	5,133
Net deferred tax assets	64,573	60,454
Deferred tax liabilities:		
Property, plant and equipment	137,185	133,710
Note receivable	11,668	14,103
Other	13,707	16,013
Deferred tax liabilities	162,560	163,826
Net deferred tax liability	$ 97,987	$ 103,372

The net deferred tax assets reflect management’s estimate of the amount that will be realized from future profitability and the reversal of taxable temporary differences that can be predicted with reasonable certainty. A valuation allowance is recognized if it is more likely than not that at least some portion of any deferred tax asset will not be realized.

As of December 31, 2005, the Company has not established a valuation allowance for its deferred tax assets. The Company believes that it is more likely than not that the tax assets will be realized because of the reversal of accelerated tax depreciation and future taxable income.

As of December 31, 2005, the Company has an estimated $5.3 million foreign tax credit carryforward with expiration dates from 2011 through 2014. As of December 31, 2005, the Company also has various state net operating loss carryforwards of an estimated $56 million with expiration dates from 2013 through 2017.

The Company has not provided United States tax expense on earnings of its foreign subsidiaries, since the Company has reinvested or expects to reinvest the undistributed earnings indefinitely. As of December 31, 2005, the undistributed earnings of the Company's foreign subsidiaries were approximately $22.9 million. If these earnings are repatriated to the United States in the future, additional tax provisions may be required. It is not practicable to estimate the amount of taxes that might be payable on such undistributed earnings.

The American Jobs Creation Act of 2004 was passed on October 22, 2004. This legislation allows, under certain conditions, a one-time tax deduction of 85% of certain foreign earnings that are repatriated prior to the end of the Company's fiscal 2005 year. The deduction would result in a 5.25% federal tax rate on the repatriated earnings. As of December 31, 2004, the Company had not determined whether earnings will be repatriated or an estimate of the possible United States federal and state income tax expense related to any potential repatriation. In 2005, the Company analyzed foreign earnings that qualified for the temporary repatriation. As a result of the analysis, the Company has determined that there was no significant benefit to the Company from this incentive because foreign tax credits would be available to reduce the impact of repatriation of foreign earnings in future years. Accordingly, the Company did not repatriate any foreign earnings in 2005.

(11) Stockholders' Equity

In December 2005, the Company's Compensation Committee of the Board of Directors granted 24,000 shares of restricted stock to its President. The restricted stock vests in three equal installments on January 2, 2006, 2007 and 2008. The Company expensed approximately $178,000 in 2005 based on the share price of $22.24 on the date of grant and will expense approximately $178,000 in 2006 and 2007, as the remaining shares vest.

In October 2004, the Company sold 9,696,627 shares of common stock that generated net proceeds (before any exercise of the underwriters' over-allotment option) of approximately $113 million, after deducting underwriting discounts and commissions and the estimated offering expenses. The Company used the net proceeds to repurchase 9,696,627 shares of its common stock from First Reserve Fund VII, Limited Partnership and First Reserve Fund VIII, L.P. The shares repurchased by the Company from the First Reserve funds were retired immediately upon repurchase. In November 2004, an additional 1,454,494 shares of the Company's common stock were issued pursuant to the exercise of the underwriters' over-allotment option generating net proceeds of approximately $17 million, after deducting underwriting discounts and commissions.

In 2004, the Superior Energy Services, Inc. 2004 Directors Restricted Stock Units Plan was approved by the Company's stockholders. This plan provides each non-employee director is granted a number of restricted stock units having an aggregate value of $30,000, with the exact number of units determined by dividing $30,000 by the fair market value of the Company's common stock on the day of the annual stockholders' meeting. In addition, upon any person's initial election or appointment as an eligible director, other than at an annual stockholders' meeting, such person will receive a pro forma number of restricted stock units based on the number of full calendar months between the date of grant and the first anniversary of the previous annual stockholders' meeting. A restricted stock unit represents the right to receive from the Company, within 30 days of the date the participant ceases to serve on the Board, one share of the Company's common stock. As a result of this plan, 19,998 restricted stock units are outstanding at December 31, 2005.

The Company maintains various stock incentive plans, including the 2002 Stock Incentive Plan (2002 Incentive Plan), the 1999 Stock Incentive Plan (1999 Incentive Plan) and the 1995 Stock Incentive Plan (1995 Incentive Plan), as amended. These plans provide long-term incentives to the Company's key employees, including officers and directors, consultants and advisers (Eligible Participants). Under the 2002 Incentive Plan, the 1999 Incentive Plan and the 1995 Incentive Plan, the Company may grant incentive stock options, non-qualified stock options, restricted stock, stock awards or any combination thereof to Eligible Participants for up to 1,400,000 shares, 5,929,327 shares and 1,900,000 shares, respectively, of the Company's common stock. The Compensation Committee of the Company's Board of Directors establishes the term and the exercise price of any stock options granted under the 2002 Incentive Plan, provided the exercise price may not be less than the fair value of the common share on the date of grant. All of the options which have been granted under the 1995 Stock Incentive Plan are vested.

A summary of stock options granted under the incentive plans for the years ended December 31, 2005, 2004 and 2003 is as follows:

	2005		2004		2003	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
Outstanding at beginning of year	5,797,295	$ 8.43	5,628,000	$ 7.53	5,518,516	$ 7.33
Granted	863,500	$ 17.46	1,490,000	$ 10.66	538,000	$ 8.94
Exercised	(2,709,624)	$ 6.94	(1,196,060)	$ 7.01	(271,913)	$ 6.72
Forfeited	(57,538)	$ 10.23	(124,645)	$ 8.14	(156,603)	$ 7.00
Outstanding at end of year	3,893,633	$ 11.44	5,797,295	$ 8.43	5,628,000	$ 7.53
Exercisable at end of year	3,759,721	$ 11.53	5,328,741	$ 8.37	4,248,244	$ 7.08
Available for future grants	3,229,784		35,746		1,401,101	
Average fair value of grants during the year		$ 7.47		$ 6.22		$ 3.59

A summary of information regarding stock options outstanding at December 31, 2005 is as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Shares	Weighted Average Remaining Contractual Life	Weighted Average Price	Shares	Weighted Average Price
$4.75 - $5.75	33,000	2.7 years	$ 5.36	33,000	$ 5.36
$7.06 - $9.00	744,610	6.1 years	$ 8.38	619,031	$ 8.30
$9.10 - $12.45	2,252,523	7.6 years	$10.23	2,244,190	$10.23
$12.50 - $17.46	863,500	9.5 years	$17.46	863,500	$17.46

(12) Profit-Sharing Plan

The Company maintains a defined contribution profit-sharing plan for employees who have satisfied minimum service and age requirements. Employees may contribute up to 75% of their earnings to the plans. The Company provides a discretionary match, not to exceed 5% of an employee's salary. The Company made contributions of approximately $1.9 million, $1.7 million and $1.6 million, in 2005, 2004 and 2003, respectively.

The Company has a nonqualified defined contribution deferred compensation plan which allows certain highly-compensated employees the option to defer up to 75% of their salary and up to 100% of their bonus compensation to the plan. Payments are made after the employee terminates, based on their distribution election and plan balance. Participants earn a return on their deferred compensation that is based on hypothetical investments in certain mutual funds. Changes in market value of these hypothetical participant investments are reflected as an adjustment to the deferred compensation liability of the Company with an offset to compensation expense. As of December 31, 2005, the liability of the Company to the participants was approximately $1.5 million and is recorded in Other Long-Term Liabilities, which reflects the accumulated participant deferrals and earnings as of that date. The Company makes contributions equal to the participant deferrals into life insurance which is invested in mutual funds similar to the participants' elections. A change in market value of the life insurance is reflected as an adjustment to the deferred compensation plan asset with an offset to interest income or expense. As of December 31, 2005, the deferred contribution plan asset was approximately $1.4 million and is recorded in Other Long-Term Assets.

(13) Commitments and Contingencies

The Company leases certain office, service and assembly facilities under operating leases. The leases expire at various dates over the next several years. Total rent expense was approximately $4.3 million in 2005, $4.2 million in 2004 and $2.3 million in 2003. Future minimum lease payments under non-cancelable leases for the five years ending December 31, 2006 through 2010 and thereafter are as follows: $6,360,000, $4,837,000, $2,723,000, $1,667,000, $1,137,000 and $14,181,000, respectively. Future minimum lease payments receivable under non-cancelable sub-leases for the years ending December 31, 2006 through 2008 are as follows: $535,000, $592,000, and $49,000, respectively.

From time to time, the Company is involved in litigation arising out of operations in the normal course of business. In management's opinion, the Company is not involved in any litigation, the outcome of which would have a material effect on its financial position, results of operations or liquidity.

(14) Segment Information

Business Segments

The Company modified its segment disclosure by combining its other oilfield services segment into the well intervention segment. In February 2006, the Company sold its environmental subsidiary, which comprised a large part of the other oilfield services segment. The remaining businesses, which include platform and field management services, environmental cleaning services and the sale of drilling instrumentation equipment, are impacted by similar factors that affect the well intervention segment. The combination of the well intervention and other oilfield services segments better reflects the way management evaluates the Company's results. The prior year segment presentation has been restated to conform to the current segment classification.

The Company's reportable segments are now as follows: well intervention, rental tools, marine, and oil and gas. The first three segments offer products and services within the oilfield services industry. The well intervention segment provides plug and abandonment services, coiled tubing services, well pumping and stimulation services, data acquisition services, gas lift services, electric wireline services, hydraulic drilling and workover services, well control services, drilling instrumentation equipment, contract operations and maintenance services, transportation and logistics services, offshore oil and gas cleaning services, engineering support, technical analysis and mechanical wireline services that perform a variety of ongoing maintenance and repairs to producing wells, as well as modifications to enhance the production capacity and life span of the well. The rental tools segment rents and sells stabilizers, drill pipe, tubulars and specialized equipment for use with onshore and offshore oil and gas well drilling, completion, production and workover activities. It also provides onsite accommodations and bolting and machining services. The marine segment operates liftboats for production service activities, as well as oil and gas production facility maintenance, construction operations and platform removals. The oil and gas segment acquires mature oil and gas properties and produces and sells any remaining economic oil and gas reserves prior to the Company's other segments providing decommissioning services. Oil and gas eliminations represent products and services provided to the oil and gas segment by the Company's three other segments.

The accounting policies of the reportable segments are the same as those described in Note 1 of these Notes to the Consolidated Financial Statements. The Company evaluates the performance of its operating segments based on operating profits or losses. Segment revenues reflect direct sales of products and services for that segment, and each segment records direct expenses related to its employees and its operations. Identifiable assets are primarily those assets directly used in the operations of each segment.

Summarized financial information concerning the Company's segments as of December 31, 2005, 2004 and 2003 and for the years then ended is shown in the following tables (in thousands):

2005	Well Interven.	Rental Tools	Marine	Oil & Gas	Oil & Gas Eliminations & Unallocated	Consolid. Total
Revenues	$339,609	$243,536	$ 87,267	$ 78,911	$(13,989)	$ 735,334
Costs of services	213,638	82,562	47,989	45,804	(13,989)	376,004
Depreciation, depletion, amortization and accretion	18,135	42,445	8,214	20,494	—	89,288
General and administrative	71,027	54,533	9,889	5,540	—	140,989
Reduction in value of assets	4,850	—	—	2,144	—	6,994
Gain on sale of liftboats	—	—	3,544	—	—	3,544
Operating income	31,959	63,996	24,719	4,929	—	125,603
Interest expense	—	—	—	—	(21,862)	(21,862)
Interest income	—	—	—	1,160	1,041	2,201
Equity in earnings of affiliates	—	1,339	—	—	—	1,339
Reduction in value of investment	—	(1,250)	—	—	—	(1,250)
Income (loss) before income taxes	$ 31,959	$ 64,085	$ 24,719	$ 6,089	$(20,821)	$ 106,031
Identifiable assets	$332,996	$405,527	$203,718	$147,667	$ 7,342	$1,097,250
Capital expenditures	$ 24,847	$ 70,227	$ 10,399	$ 19,693	$ —	$ 125,166

2004	Well Interven.	Rental Tools	Marine	Oil & Gas	Oil & Gas Eliminations & Unallocated	Consolid. Total
Revenues	$295,690	$170,064	$ 69,808	$ 37,008	$ (8,231)	$ 564,339
Costs of services	189,858	57,353	49,581	21,547	(8,231)	310,108
Depreciation, depletion, amortization and accretion	17,435	32,527	7,362	10,013	—	67,337
General and administrative	58,703	42,165	7,085	2,652	—	110,605
Operating income	29,694	38,019	5,780	2,796	—	76,289
Interest expense	—	—	—	—	(22,476)	(22,476)
Interest income	—	—	—	1,648	118	1,766
Equity in earnings of affiliates	—	1,329	—	—	—	1,329
Income (loss) before income taxes	$ 29,694	$ 39,348	$ 5,780	$ 4,444	$(22,358)	$ 56,908
Identifiable assets	$313,431	$357,762	$184,928	$141,179	$ 6,613	$1,003,913
Capital expenditures	$ 12,735	$ 50,687	$ 5,523	$ 5,180	$ —	$ 74,125

2003	Well Interven.	Rental Tools	Marine	Oil & Gas	Unallocated	Consolid. Total
Revenues	$288,152	$141,362	$ 70,370	$ 741	$ —	$500,625
Costs of services	192,843	46,119	50,314	331	—	289,607
Depreciation, depletion, amortization and accretion	16,361	25,696	6,665	131	—	48,853
General and administrative	54,215	33,457	7,122	28	—	94,822
Operating income	24,733	36,090	6,269	251	—	67,343
Interest expense	—	—	—	—	(22,477)	(22,477)
Interest income	—	—	—	51	158	209
Other income	—	—	2,762	—	—	2,762
Equity in earnings of affiliates	—	985	—	—	—	985
Income (loss) before income taxes	$ 24,733	$ 37,075	$ 9,031	$ 302	$(22,319)	$ 48,822
Identifiable assets	$288,443	$314,122	$181,752	$41,315	$ 7,231	$832,863
Capital expenditures	$ 17,940	$ 30,192	$ 2,043	$ —	$ —	$ 50,175

Geographic Segments

The Company attributes revenue to various countries based on the location of where services are performed or the destination of the sale of products. Long-lived assets consist primarily of property, plant, and equipment and are attributed to various countries based on the physical location of the asset at a given fiscal year-end. The Company's information by geographic area is as follows (amounts in thousands):

	Revenues Years Ended December 31,			Long-Lived Assets December 31,	
	2005	2004	2003	2005	2004
United States	$636,062	$476,771	$443,936	$492,602	$479,812
Other Countries	99,272	87,568	56,689	42,360	35,339
Total	$735,334	$564,339	$500,625	$534,962	$515,151

(15) Interim Financial Information (Unaudited)

The following is a summary of consolidated interim financial information for the years ended December 31, 2005 and 2004 (amounts in thousands, except per share data):

	Three Months Ended			
	March 31	June 30	Sept. 30	Dec. 31
2005				
Revenues	$ 173,247	$ 190,000	$ 184,101	$ 187,986
Gross profit	86,829	99,348	82,704	90,449
Net income	17,209	25,054	9,358	16,238
Earnings per share:				
Basic	$ 0.22	$ 0.32	$ 0.12	$ 0.20
Diluted	0.22	0.32	0.12	0.20

	Three Months Ended			
	March 31	June 30	Sept. 30	Dec. 31
2004				
Revenues	$ 116,459	$ 137,545	$ 152,500	$ 157,835
Gross profit	49,754	60,401	70,089	73,987
Net income	3,564	8,714	11,288	12,286
Earnings per share:				
Basic	$ 0.05	$ 0.12	$ 0.15	$ 0.16
Diluted	0.05	0.12	0.15	0.16

(16) Supplementary Oil and Natural Gas Disclosures (Unaudited)

The Company's December 31, 2005 and 2004 estimates of proved reserves are based on reserve reports prepared by DeGolyer and MacNaughton, independent petroleum engineers. The estimates of proved reserves at December 31, 2003 are based on internal reports. Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. This data may also change substantially over time as a result of multiple factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

The following table sets forth the Company's net proved reserves, including the changes therein, and proved developed reserves:

	Crude Oil (Mbbls)	Natural Gas (Mmcf)
Proved-developed and undeveloped reserves:		
December 31, 2002	—	—
Purchase of reserves in place	193	3,304
Revisions	—	(1)
Production	(3)	(79)
December 31, 2003	190	3,224
Purchase of reserves in place	9,232	17,968
Revisions	88	11,407
Production	(390)	(3,219)
December 31, 2004	9,120	29,380
Purchase of reserves in place	168	2,925
Revisions (1)	1,036	(5,294)
Production	(1,221)	(3,323)
December 31, 2005	9,103	23,688
Proved-developed reserves:		
December 31, 2003	64	3,190
December 31, 2004	7,731	25,542
December 31, 2005	7,554	21,703

(1) The downward revisions in 2005 were primarily attributable to three factors: 1) the Company determined that it would not undertake four previously planned behind pipe recompletions, 2) one well was plugged and abandoned after experiencing continuing mechanical difficulties, and 3) production rates from several wells after their acquisition by the Company did not support the reserve level initially established.

Since January 1, 2005 no crude oil or natural gas reserve information has been filed with, or included in any report to any federal authority or agency other than the SEC and the Energy Information Administration ("EIA"). The Company files Form 23, including reserve and other information with the EIA.

Costs incurred for oil and natural gas property acquisition and development activities for the years ended December 31, 2005, 2004 and 2003 are as follows (in thousands):

	Years Ended December 31, 2005	2004	2003
Acquisition of properties — proved	$ 9,015	$ 81,356	$ 5,041
Development costs	19,867	4,707	—
Total costs incurred	$ 28,882	$ 86,063	$ 5,041

<u>Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves</u>

The following information has been developed utilizing procedures prescribed by Statement of Financial Accounting Standards No. 69 (FAS No. 69), "Disclosure about Oil and Gas Producing Activities." It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account in reviewing the following information: (1) future costs and selling prices will probably differ from those required to be used in these calculations; (2) due to future market conditions and governmental regulations, actual rates of production achieved in future years may vary significantly from the rate of production assumed in the calculations; (3) selection of a 10% discount rate is arbitrary and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and (4) future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by applying period end oil and natural gas prices adjusted for differentials provided by the Company. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs in order to arrive at net cash flow before tax. Future income tax expense has been computed by applying period-end statutory tax rates to aggregate future net cash flows, reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate is required by FAS No. 69.

The Company's management does not rely solely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows (in thousands):

	2005	2004	2003
Future cash inflows	$ 792,246	$ 587,277	$ 26,002
Future production costs	(155,282)	(148,610)	(12,603)
Future development and abandonment costs	(195,415)	(153,230)	(6,641)
Future income tax expense	(171,058)	(119,567)	(2,748)
Future net cash flows after income taxes	270,491	165,870	4,010
10% annual discount for estimated timing of cash flows	65,386	29,363	20
Standardized measure of discounted future net cash flows	$ 205,105	$ 136,507	$ 3,990

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the years ended December 31, 2005, 2004 and 2003 is as follows (in thousands):

	2005	2004	2003
Beginning of the period	$ 136,507	$ 3,990	$ —
Sales and transfers of oil and natural gas produced, net of production costs	(34,563)	(15,467)	(470)
Net changes in prices and production costs	156,992	949	(1)
Revisions of quantity estimates	4,314	46,040	(8)
Development costs incurred	19,867	4,707	—
Changes in estimated development costs	(46,113)	(99,253)	(5,496)
Purchase and sales of reserves in place	18,408	282,935	12,552
Changes in production rates (timing) and other	(25,536)	(3,238)	(13)
Accretion of discount	22,123	656	—
Net change in income taxes	(46,894)	(84,812)	(2,574)
Net increase	68,598	132,517	3,990
End of period	$ 205,105	$ 136,507	$ 3,990

The December 31, 2005 amount was estimated by DeGolyer and MacNaughton using a period-end crude NYMEX price of $61.04 per barrel (bbl), a NYMEX gas price of $9.44 per million British Thermal units, and price differentials provided by the Company. The December 31, 2004 amount was estimated by DeGolyer and MacNaughton using a period-end crude NYMEX price of $43.46 per bbl, a Henry Hub gas price of $6.19 per million British Thermal units, and price differentials provided by the Company. The December 31, 2003 amount was estimated by the Company using a period end oil price of $32.55 per bbl and $6.14 per thousand cubic feet (mcf) for natural gas. The Company had no oil and gas holdings prior to 2003. Spot prices as of February 28, 2006 were $6.71 per million British Thermal units for natural gas and $61.41 per bbl for crude oil.

(17) Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board revised its Statement of Financial Accounting Standards No. 123 (FAS No. 123R), “Accounting for Stock Based Compensation.” Under FAS No. 123R, companies will be required to recognize as expense the estimated fair value of all share-based payments to employees, including the fair value of employee stock options. This expense will be recognized over the period during which the employee is required to provide service in exchange for the award. Pro forma disclosure of the estimated expense impact of such awards is no longer an alternative to expense recognition in the financial statements. FAS No. 123R is effective for public companies in the first annual period beginning after June 15, 2005, and accordingly, the Company will adopt the provisions of FAS No. 123R effective January 1, 2006. The Company anticipates using the modified prospective application transition method, which does not include restatement of prior periods. The Company expects to record approximately $89,000 of compensation expense in 2006 due to the adoption of FAS No. 123R for share-based awards granted prior to January 1, 2006. The Company expects the effect of the adoption on future share-based awards to be consistent with the disclosure of pro forma net income and earnings per share as displayed in note 1 of its consolidated financial statements.

In May 2005, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 154 (FAS No. 154), “Accounting Changes and Error Corrections.” This Statement replaces APB Opinion No. 20, “Accounting Changes” and FASB Statement No. 3, “Reporting Accounting Changes in Interim Financial Statements.” FAS No. 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes, unless impracticable, retrospective application as the required method for reporting all changes in accounting principle in the absence of explicit transition requirements of new pronouncements. FAS No. 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005.