SUPERIOR ENERGY SERVICES INC
Form 10-K
February 26, 2010

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

þ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2009

or

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the Transition Period from __________ to __________

Commission File No. 001-34037
SUPERIOR ENERGY SERVICES, INC.
(Exact name of registrant as specified in its charter)

Delaware	75-2379388
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
601 Poydras, Suite 2400 New Orleans, LA	70130
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number: (504) 587-7374
Securities registered pursuant to Section 12(b) of the Act:

Title of each class:	Name of each exchange on which registered:
Common Stock, $.001 Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer o	Non-accelerated o	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate market value of the voting stock held by non-affiliates of the registrant at June 30, 2009 based on the closing price on the New York Stock Exchange on that date was $1,343,725,000.

The number of shares of the registrant s common stock outstanding on February 18, 2010 was 78,530,517.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information called for by Items 10, 11, 12, 13 and 14 of Part III is incorporated by reference from the registrant s definitive proxy statement to be filed pursuant to Regulation 14A.

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FORWARD-LOOKING STATEMENTS

We have included or incorporated by reference in this Annual Report on Form 10-K, and from time to time our management may make statements that may constitute forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are not historical facts but instead represent only our current belief regarding future events, many of which, by their nature, are inherently uncertain and outside our control. The forward-looking statements contained in this Annual Report on Form 10-K are based on information as of the date of this report. Many of these forward-looking statements relate to future industry trends, actions, future performance or results of current and anticipated initiatives and the outcome of contingencies and other uncertainties that may have a significant impact on our business, future operating results and liquidity. We try, whenever possible, to identify these statements by using words such as anticipate, believe, should, estimate, expect, plan, project and similar expressions. We caution you that these statements are only predictions an are not guarantees of future performance. These forward-looking statements and our actual results, developments and business are subject to certain risks and uncertainties that could cause actual results and events to differ materially from those anticipated by these statements. By identifying these statements for you in this manner, we are alerting you to the possibility that our actual results may differ, possibly materially, from the anticipated results indicated in these forward-looking statements. Important factors that could cause actual results to differ from those in the forward-looking statements include, among others, those discussed below and under Risk Factors in Part I, Item 1A and Management s Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7.

PART I

Item 1. Business

General

We believe we are a leading, highly diversified provider of specialized oilfield services and equipment. We focus on serving the drilling-related needs of oil and gas companies primarily through our drilling products and services segment, and the production-related needs of oil and gas companies through our subsea and well enhancement and marine segments. We believe that we are one of the few companies capable of providing the services and tools necessary to maintain, enhance and extend the life of producing wells, as well as plug and abandonment services at the end of their life cycle. We also own oil and gas properties in the Gulf of Mexico. We believe that our ability to provide our customers with multiple services and to coordinate and integrate their delivery, particularly offshore through the use of our liftboats, allows us to maximize efficiency, reduce lead time and provide cost effective solutions for our customers. We have expanded geographically so that we now have a significant presence in both select domestic land and international markets.

Operations

During 2009, we renamed two of our segments in order to more accurately describe the markets and customers served by the businesses operating in each segment. The content of these segments has not changed. Our operations are organized into the following business segments:

Subsea and Well Enhancement (formerly Well Intervention). We provide subsea and well enhancement services that are used to build out oil and gas production infrastructure, stimulate oil and gas production, plug and abandon uneconomic or non-producing wells and decommission offshore oil and gas platforms. Our subsea and well enhancement services include coiled tubing, electric line, pumping and stimulation, gas lift, well control, snubbing, recompletion, engineering and well evaluation, offshore oil and gas tank and vessel cleaning, decommissioning, plug and abandonment and mechanical wireline. We believe we are the leading provider of wireline services in the Gulf of Mexico with approximately 142 offshore wireline units, 24 offshore electric line units, seven offshore coiled tubing units and 10 dedicated liftboats configured specifically for wireline services. We also own and operate 43 land wireline units, 68 land electric line units and 32 land coiled tubing units. Additionally, we own two derrick barges each equipped with an 880 metric ton crane. We also manufacture and sell specialized drilling rig instrumentation equipment.

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In January 2010, we acquired Hallin Marine Subsea Plc (Hallin), an international provider of integrated subsea services and engineering solutions, focused on installing, maintaining and extending the life of subsea wells. The acquisition of Hallin provides us the opportunity to enhance our position in the subsea and well enhancement market through existing subsea assets (remotely operated vehicles, saturation diving systems and chartered vessels) and a newbuild vessel program.

Drilling Products and Services (formerly Rental Tools). We believe we are a leading provider of drilling products and services. We manufacture, sell and rent specialized equipment for use with offshore and onshore oil and gas well drilling, completion, production and workover activities. Through internal growth and acquisitions, we have increased the size and breadth of our drilling products inventory and geographic scope of operations so that we now conduct operations offshore in the Gulf of Mexico, onshore in the United States and in select international market areas. We currently have locations in all of the major staging points in Louisiana and Texas for oil and gas activities in the Gulf of Mexico, and in North Louisiana, Texas, Arkansas, Oklahoma, Colorado, Pennsylvania, and Wyoming. Our drilling products and services segment conducts operations in Latin America, North America, the North Sea region, Continental Europe, the Middle East, Central Asia, West Africa and the Asia Pacific region. Our drilling products and services include pressure control equipment, specialty tubular goods including drill pipe and landing strings, connecting iron, handling tools, stabilizers, drill collars and on-site accommodations.

Marine Services. We own and operate a fleet of liftboats that we believe is highly complementary to our subsea and well enhancement services. A liftboat is a self-propelled, self-elevating work platform with legs, cranes and living accommodations. Our fleet consists of 26 liftboats with leg lengths ranging from 145 feet to 265 feet. Our liftboat fleet has leg lengths and deck spaces that are suited to deliver our production-related bundled services and support customers in their construction, maintenance and other production enhancement projects. All of our liftboats are currently located in the Gulf of Mexico and the Caribbean.

Oil and Gas Operations. On March 14, 2008, we completed the sale of 75% of our interest in SPN Resources, LLC (SPN Resources). As part of this transaction, SPN Resources contributed an undivided 25% of its working interest in each of its oil and gas properties to a newly formed subsidiary and then sold all of its equity interest in the subsidiary. SPN Resources then effectively sold 66 2/3% of its outstanding membership interests. SPN Resources operations constituted substantially all of our oil and gas segment. Subsequent to the sale of control of SPN Resources, we account for our remaining interest in SPN Resources using the equity-method within the oil and gas segment (see note 4 to our consolidated financial statements included in Item 8 of this Form 10-K).

Our equity-method investments, SPN Resources and DBH, LLC (DBH), the successor company of Beryl Oil and Gas, LP, as well as our recent acquisition of Bullwinkle platform and related assets from Shell Offshore, LLC, provide us additional opportunities for our subsea and well enhancement, decommissioning and platform management services. SPN Resources and DBH utilize our production-related assets and services to maintain, enhance and extend existing production of these properties. At the end of a property s economic life, we offer services to plug and abandon the wells and decommission and abandon the facilities.

For additional industry segment financial information, see note 14 to our consolidated financial statements included in Item 8 of this
Form 10-K.

Customers

Our customers are the major and independent oil and gas companies that are active in the geographic areas in which we operate. Of our 2009 and 2008 total revenue, Chevron accounted for approximately 15% and 12%, respectively, Apache accounted for approximately 13% and 11%, respectively, and BP accounted for approximately 11%. Sales to Shell accounted for approximately 11% of our total revenue in 2007. Our inability to continue to perform services for a number of our large existing customers, if not offset by sales to new or other existing customers, could have a material adverse effect on our business and operations.

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Competition

We operate in highly competitive areas of the oilfield services industry. The products and services of each of our operating segments are sold in highly competitive markets, and our revenues and earnings can be affected by the following factors:

- changes in competitive prices;
- oil and gas prices and industry perceptions of future prices;
- fluctuations in the level of activity by oil and gas producers;
- changes in the number of liftboats operating in the Gulf of Mexico;
- the ability of oil and gas producers to generate capital;
- general economic conditions; and
- governmental regulation.

We compete with the oil and gas industry s largest integrated oilfield service providers in the production-related services provided by our subsea and well enhancement segment. The rental tool divisions of these companies, as well as several smaller companies that are single source providers of rental tools, are our competitors in the drilling products and services market. In the marine services segment, we compete with other companies that provide liftboat services. We believe that the principal competitive factors in the market areas that we serve are price, product and service quality, safety record, equipment availability and technical proficiency.

Our operations may be adversely affected if our current competitors or new market entrants introduce products or services with better features, performance, prices or other characteristics than our products and services. Further, if our competitors construct additional liftboats, it could affect vessel utilization and resulting day rates. Competitive pressures or other factors also may result in significant price competition that could reduce our operating cash flow and earnings. In addition, competition among oilfield service and equipment providers is affected by each provider s reputation for safety and quality. Although we believe that our reputation for safety and quality service is good, we cannot assure that we will be able to maintain our competitive position.

Potential Liabilities and Insurance

Our operations involve a high degree of operational risk, particularly of personal injury, damage or loss of equipment and environmental accidents. Failure or loss of our equipment could result in property damages, personal injury, environmental pollution and other damages for which we could be liable. Litigation arising from the sinking of a marine vessel or a catastrophic occurrence, such as a fire, explosion or well blowout at a location where our equipment and services are used may result in large claims for damages. We maintain insurance against risks that we believe is consistent in types and amounts with industry standards and is required by our customers. Changes in the insurance industry in the past few years have led to higher insurance costs and deductibles as well as lower coverage limits, causing us to rely on self-insurance against many risks associated with our business. The availability of insurance covering risks we typically insure against may continue to decrease, and the costs of such insurance and deductibles may continue to increase, forcing us to self-insure against more business risks, including the risks associated with hurricanes. The insurance that we are able to obtain may have higher deductibles, higher premiums, lower limits and more restrictive policy terms.

Health, Safety and Environmental Assurance

We have established health, safety and environmental performance as a corporate priority. Our goal is to be an industry leader in this area by focusing on the belief that all safety and environmental incidents are preventable and an injury-free workplace is achievable by emphasizing correct behavior. We have a company-wide effort to enhance our behavioral safety process and training program to make safety a constant area of focus through open communication with all of our offshore, onshore and yard employees. In addition, we investigate all incidents with a priority of identifying and implementing the corrective measures necessary to reduce the chance of reoccurrence.

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Government Regulation

Our business is significantly affected by the following:

- federal, state and international laws and other regulations relating to the oil and gas industry;
- changes in such laws and regulations; and
- the level of enforcement thereof.

We cannot predict the level of enforcement of existing laws and regulations or how such laws and regulations may be interpreted by enforcement agencies or court rulings in the future. A change in the level of industry compliance with or enforcement of these laws and regulations in the future may adversely affect the demand for our services. We also cannot predict whether additional laws and regulations will be adopted, or the effect such changes may have on us, our businesses or our financial condition. The demand for our services from the oil and gas industry would be affected by changes in applicable laws and regulations. The adoption of new laws and regulations curtailing drilling for oil and gas in our operating areas for economic, environmental or other policy reasons could also adversely affect our operations by limiting demand for our services.

Environmental Regulations

General. Our operations are subject to extensive federal, state and local laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Permits are required for the conduct of our business and operation of our various marine vessels. These permits can be revoked, modified or renewed by issuing authorities. Governmental authorities enforce compliance with their regulations through administrative or civil penalties, corrective action orders, injunctions or criminal prosecution. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities related to environmental compliance issues are part of our operations. No assurance can be given that significant costs and liabilities will not be incurred.

Federal laws and regulations applicable to our operations include those controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment, requiring consistency with applicable coastal zone management plans, or otherwise relating to the protection of the environment.

Our insurance policies provide liability coverage for sudden and accidental occurrences of pollution or clean up and containment in amounts that we believe are prudent and comparable to policy limits carried by others in our industry.

Outer Continental Shelf Lands Act. The Outer Continental Shelf Lands Act (OCSLA) and regulations promulgated pursuant thereto impose a variety of regulations relating to safety and environmental protection applicable to lessees, permittees and other parties operating on the Outer Continental Shelf. Specific design and operational standards may apply to Outer Continental Shelf vessels, rigs, platforms, vehicles and structures. Violations of lease conditions or regulations issued pursuant to OCSLA can result in substantial civil and criminal penalties as well as potential court injunctions curtailing operations and the cancellation of leases. Enforcement liabilities under OCSLA can result from either governmental or citizen prosecution. We believe that we substantially comply with OCSLA and its regulations.

Solid and Hazardous Waste. We own and lease numerous properties that have been used in connection with the production of oil and gas for many years. Although we believe we utilize operating and disposal practices that are standard in the industry, it is possible that hydrocarbons or other solid wastes may have been disposed of or released on or under the properties owned and leased by us. Federal and state laws applicable to oil and gas wastes and properties continue to be stricter over time. Under these increasingly stringent requirements, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners and operators) or clean up property contamination (including groundwater contamination by prior owners or operators) or to perform plugging operations to prevent future contamination. We generate some hazardous wastes that are already subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (EPA) has limited the disposal options for certain hazardous wastes. It is possible that certain wastes currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes. We could, therefore, be subject to more rigorous and costly disposal requirements in the future than we encounter today.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release of hazardous substances into the environment. These persons include the owner and operator of a site and any party that disposed of or arranged for the disposal of hazardous substances found at a site. CERCLA also authorizes the EPA, and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In the course of business, we have generated and will continue to generate wastes that may fall within CERCLA s definition of hazardous substances. We may also be an operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such wastes have been disposed.

Oil Pollution Act. The Federal Oil Pollution Act of 1990 (OPA) and resulting regulations impose a variety of obligations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. The term waters of the United States has been broadly defined to include inland water bodies, including wetlands and intermittent streams. OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. We believe that we substantially comply with OPA and related federal regulations.

Clean Water Act. The Federal Water Pollution Control Act (Clean Water Act) and resulting regulations, which are implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure to comply strictly with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease operation of our marine vessels that are the source of water discharges. We believe that we substantially comply with the Clean Water Act and related federal and state regulations.

Clean Air Act. Our operations are subject to local, state and federal laws and regulations to control emissions from sources of air pollution. Payment of fines and correction of any identified deficiencies generally resolve penalties for failure to comply strictly with air regulations or permits. Regulatory agencies could also require us to cease operation of certain marine vessels that are air emission sources. We believe that we substantially comply with the emission standards under local, state, and federal laws and regulations.

Maritime Employees

Certain of our employees who perform services on offshore platforms and marine vessels are covered by the provisions of the Jones Act, the Death on the High Seas Act and general maritime law. These laws operate to make the liability limits established under state workers compensation laws inapplicable to these employees. Instead, these employees or their representatives are permitted to pursue actions against us for damages resulting from job related injuries, with generally no limitations on our potential liability.

Employees

As of January 31, 2010, we had approximately 4,800 employees. None of our employees is represented by a union or covered by a collective bargaining agreement. We believe that our relationship with our employees is good.

Facilities

Our principal executive offices are located at 601 Poydras Street, Suite 2400, New Orleans, Louisiana 70130. We own an operating facility on a 17-acre tract in Harvey, Louisiana, which we use to support our subsea and well enhancement, drilling products and services, and marine operations. Our other principal operating facility is located on a 32-acre tract in Broussard, Louisiana, which we use to support our drilling products and services and subsea and well enhancement operations in the Gulf of Mexico. We support the operations conducted by our liftboats from a 3.5-acre maintenance and office facility in New Iberia, Louisiana. We also own certain facilities and lease other office, service and assembly facilities under various operating leases, including a 7-acre office and training facility located in Houston, Texas. We have a total of approximately 150 owned or leased operating facilities located throughout the world. We believe that all of our leases are at competitive or market rates and do not anticipate any difficulty in leasing suitable additional space as may be needed or extending terms when our current leases expire.

Intellectual Property

We use several patented items in our operations that we believe are important, but not indispensable, to our operations. Although we anticipate seeking patent protection when possible, we rely to a greater extent on the technical expertise and know-how of our personnel to maintain our competitive position.

Other Information

We have our principal executive offices at 601 Poydras Street, Suite 2400, New Orleans, Louisiana 70130. Our telephone number is (504) 587-7374. We also have a website at http://www.superiorenergy.com. Copies of the annual, quarterly and current reports we file with the SEC, and any amendments to those reports, are available on our website free of charge soon after such reports are filed with or furnished to the SEC. The information posted on our website is not incorporated into this Annual Report on Form 10-K. Alternatively, you may access these reports at the SEC s internet website: http://www.sec.gov/ .

We have adopted a Code of Business Ethics and Conduct, which applies to all of our directors, officers and employees. The Code of Business Ethics and Conduct is publicly available on our website at http://www.superiorenergy.com. Any waivers to the Code of Business Ethics and Conduct by directors or executive officers and any material amendment to the Code of Business Ethics and Conduct will be posted promptly on our website and/or disclosed in a current report on Form 8-K.

Item 1A. Risk Factors

You should carefully consider the following factors in addition to the other information contained in this Annual Report. The risks described below are the material risks that we have identified. There are many factors that affect our business and the results of our operations, many of which are beyond our control. In addition, they may not be the only material risks that we face. Additional risks and uncertainties not currently known to us or that we currently view as immaterial may also impair our business operations. If any of these risks develop into actual events, it could materially and adversely affect our business, financial condition, results of operations and cash flows. If that occurred, the trading price of our common stock could decline and you could lose part or all of your investment.

Adverse macroeconomic and business conditions may significantly and negatively affect our results of operations.

Economic conditions in the United States and in foreign markets in which we operate could substantially affect our revenue and profitability. The domestic and global financial crisis, the associated fluctuating oil and gas prices, and the unprecedented levels of disruption and continuing illiquidity in the credit markets have had an adverse effect on our operating results and financial condition, and if sustained or worsened, such adverse effects could continue or worsen. Additionally, as a result of continuing illiquidity in the credit markets, some of our suppliers and customers are facing credit issues and could experience cash flow problems and other financial hardships.

Changes in governmental banking, monetary and fiscal policies to restore liquidity and increase credit availability may not be effective. It is difficult to determine the breadth and duration of the domestic and global financial crisis and the many ways in which it may affect our suppliers, customers and our business in general. The continuation or further deterioration of these difficult financial and macroeconomic conditions could have a significant adverse effect on our results of operations and cash flows.

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Our access to borrowing capacity could be affected by the turmoil and uncertainty impacting credit markets generally.

Disruptions in the credit and financial markets have adversely affected financial institutions, inhibited lending and limited access to capital and credit for many companies. Several large financial institutions have either recently failed or been dependent on the assistance of the U.S. federal government to continue to operate as a going concern. Although we believe that the banks participating in our credit facility have adequate capital and resources, we can provide no assurance that all of these banks will continue to operate as a going concern in the future. If any of the banks in our lending group were to fail, it is possible that the borrowing capacity under our credit facility would be reduced. In the event that the availability under our credit facility was reduced significantly, we could be required to obtain capital from alternate sources in order to finance our capital needs. Our options for addressing such capital constraints would include, but not be limited to (1) obtaining commitments from the remaining banks in the lending group or from new banks to fund increased amounts under the terms of our credit facility, (2) accessing the public capital markets, or (3) delaying certain projects. If it became necessary to access additional capital, it is likely that any such alternatives in the current market would be on terms less favorable than under our existing credit facility terms, which could have a material effect on our consolidated financial position, results of operations and cash flows.

If future financing is not available to us when required, as a result of limited access to the credit markets or otherwise, or is not available to us on acceptable terms, we may be unable take advantage of business opportunities or respond to competitive pressures, either of which could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

We are subject to the cyclical nature of the oil and gas industry.

The continued financial crisis in the global economy has led to fluctuating oil and natural gas prices and a lower number of rigs drilling. These conditions may result in continued reductions in capital expenditures by our customers, project cancellations if project economics become unprofitable and shut-in oil and natural gas production. As long as these conditions prevail, we expect reduced pricing and utilization for our products and services, especially in North America.

Demand for the majority of our oilfield services is substantially dependent on the level of expenditures by the oil and gas industry. This level of activity has traditionally been volatile as a result of sensitivities to oil and gas prices and generally dependent on the industry s view of future oil and gas prices. The purchases of the products and services we provide are, to a substantial extent, deferrable in the event oil and gas companies reduce expenditures. Therefore, the willingness of our customers to make expenditures is critical to our operations. Oil and gas prices have recently been very volatile and are affected by many factors, including the following:

- the level of worldwide oil and gas exploration and production;
- the cost of exploring for, producing and delivering oil and gas;
- demand for energy, which is affected by worldwide economic activity and population growth;
- the ability of the Organization of Petroleum Exporting Countries, or OPEC, to set and maintain production levels for oil;
- the discovery rate of new oil and gas reserves;
- political and economic uncertainty, socio-political unrest and regional instability or hostilities; and
- technological advances affecting energy exploration, production and consumption.

Although activity levels in production and development sectors of the oil and gas industry are less immediately affected by changing prices and as a result, less volatile than the exploration sector, producers generally react to declining oil and gas prices by reducing expenditures. This has in the past adversely affected and may in the future adversely affect our business. We are unable to predict future oil and gas prices or the level of oil and gas industry activity. A prolonged low level of activity in the oil and gas industry will adversely affect the demand for our products and services and our financial condition, results of operations and cash flows.

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Our industry is highly competitive.

We operate in highly competitive areas of the oilfield services industry. The products and services of each of our principal industry segments are sold in highly competitive markets, and our revenues and earnings may be affected by the following factors:

- changes in competitive prices;
- fluctuations in the level of activity in major markets;
- an increased number of liftboats in the Gulf of Mexico;
- general economic conditions; and
- governmental regulation.

We compete with the oil and gas industry s largest integrated and independent oilfield service providers. We believe that the principal competitive factors in the market areas that we serve are price, product and service quality, safety record, equipment availability and technical proficiency.

Our operations may be adversely affected if our current competitors or new market entrants introduce new products or services with better features, performance, prices or other characteristics than our products and services. Further, additional liftboat capacity in the Gulf of Mexico would increase competition for that service. Competitive pressures or other factors also may result in significant price competition that could have a material adverse effect on our results of operations and financial condition. Finally, competition among oilfield service and equipment providers is also affected by each provider s reputation for safety and quality. Although we believe that our reputation for safety and quality service is good, we cannot guarantee that we will be able to maintain our competitive position.

A significant portion of our revenue is derived from our non-United States operations, which exposes us to additional political, economic and other uncertainties.

Our non-United States revenues accounted for approximately 22%, 17% and 19% of our total revenues in 2009, 2008, and 2007, respectively. Our international operations are subject to a number of risks inherent in any business operating in foreign countries including, but not limited to the following:

- political, social and economic instability;
- potential expropriation, seizure or nationalization of assets;
- increased operating costs;
- social unrest, acts of terrorism, war or other armed conflict;
- renegotiating, cancellation or forced modification of contracts;
- import-export quotas;
- confiscatory taxation or other adverse tax policies;
- currency fluctuations;
- restrictions on the repatriation of funds;
- submission to the jurisdiction of a foreign court or arbitration panel or having to enforce the judgment of a foreign court or arbitration panel against a sovereign nation within its own territory; and

- other forms of government regulation which are beyond our control.

Additionally, our competitiveness in international market areas may be adversely affected by regulations, including, but not limited to the following:

- the awarding of contracts to local contractors;
- the employment of local citizens; and
- the establishment of foreign subsidiaries with significant ownership positions reserved by the foreign government for local citizens.

The occurrence of any of the risks described above could adversely affect our results of operations and cash flows.

We are susceptible to adverse weather conditions in the Gulf of Mexico.

Certain areas in and near the Gulf of Mexico experience hurricanes and other extreme weather conditions on a relatively frequent basis. Substantially all of our assets offshore and along the Gulf of Mexico are susceptible to damage and/or total loss by these storms. Damage caused by high winds and turbulent seas could potentially cause us to curtail service operations for significant periods of time until damage can be assessed and repaired. Moreover, even if we do not experience direct damage from any of these storms, we may experience disruptions in our operations because customers may curtail their development activities due to damage to their platforms, pipelines and other related facilities.

Due to the losses as a consequence of the hurricanes that occurred in the Gulf of Mexico in recent years, we have not been able to obtain insurance coverage comparable with that of prior years, thus putting us at a greater risk of loss due to severe weather conditions. Any significant uninsured losses could have a material adverse effect on our financial position, results of operations and cash flows.

We depend on key personnel.

Our success depends to a great degree on the abilities of our key management personnel, particularly our chief executive and operating officers and other high-ranking executives. The loss of the services of one or more of these key employees could adversely affect us.

We might be unable to employ a sufficient number of skilled workers.

The delivery of our products and services require personnel with specialized skills and experience. As a result, our ability to remain productive and profitable will depend upon our ability to employ and retain skilled workers. In addition, our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers in our industry is high, and the supply is limited. In addition, although our employees are not covered by a collective bargaining agreement, the marine services industry has in the past been targeted by maritime labor unions in an effort to organize Gulf of Mexico employees. A significant increase in the wages paid by competing employers or the unionization of our Gulf of Mexico employees could result in a reduction of our skilled labor force, increases in the wage rates that we must pay or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

We depend on significant customers.

We derive a significant amount of our revenue from a small number of major and independent oil and gas companies. Of our 2009 and 2008 total revenue, Chevron accounted for approximately 15% and 12%, respectively, Apache accounted for approximately 13% and 11%, respectively, and BP accounted for approximately 11%. Shell accounted for approximately 11% of our total revenue in 2007. Our inability to continue to perform services for a number of our large existing customers, if not offset by sales to new or other existing customers, could have a material adverse effect on our business and operations.

The terms of our contracts could expose us to unforeseen costs and costs not within our control.

Under fixed-price contracts, turnkey or modified turnkey contracts, we agree to perform the contract for a fixed price or a defined scope of work and extra work, which is subject to customer approval, and is billed separately. As a result, we can improve our expected profit by superior contract performance, productivity, worker safety and other factors resulting in cost savings. However, we could incur cost overruns above the approved contract price, which may not be recoverable. Prices for these contracts are established based largely upon estimates and assumptions relating to project scope and specifications, personnel and material needs. These estimates and assumptions may prove inaccurate or conditions may change due to factors out of our control, resulting in cost overruns, which we may be required to absorb and could have a material adverse effect on our business, financial condition and results of operations. In addition, our profits from these contracts could decrease and we could experience losses if we incur difficulties in performing the contracts or are unable to secure suitable commitments from our subcontractors and other suppliers. Many of these contracts require us to satisfy specified progress milestones or performance standards in order to receive payment. Under these types of arrangements, we may incur significant costs for

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equipment, labor and supplies prior to receipt of payment. If the customer fails or refuses to pay us for any reason, there is no assurance we will be able to collect amounts due to us for costs previously incurred. In some cases, we may find it necessary to terminate subcontracts and we may incur costs or penalties for canceling our commitments to them. If we are unable to collect amounts owed to us under these contracts, we may be required to record a charge against previously recognized earnings related to the project, and our liquidity, financial condition and results of operations could be adversely affected.

Percentage-of-completion accounting for contract revenue may result in material adjustments.

In 2009 and 2008, a portion of our revenue was recognized using the percentage-of-completion method of accounting. The percentage-of-completion accounting practices that we use result in our recognizing contract revenue and earnings ratably over the contract term based on the proportion of actual costs incurred to our estimated total contract costs. The earnings or losses recognized on individual contracts are based on estimates of contract revenue and costs. We review our estimates of contract revenue, costs and profitability on a monthly basis. Prior to contract completion, we may adjust our estimates on one or more occasions as a result of changes in cost estimates, change orders to the original contract, collection disputes with the customer on amounts invoiced or claims against the customer for extra work or increased cost due to customer-induced delays and other factors. Contract losses are recognized in the fiscal period in which the loss is determined. Contract profit estimates are also adjusted in the fiscal period in which it is determined that an adjustment is required. No restatements are made to prior periods for changes in these estimates. As a result of the requirements of the percentage-of-completion method of accounting, the possibility exists, for example, that we could have estimated and reported a profit on a contract over several prior periods and later determine that all or a portion of such previously estimated and reported profits were overstated or understated. If this occurs, the cumulative impact of the change will be reported in the period in which such determination is made, thereby eliminating all or a portion of any profits related to long-term contracts that would have otherwise been reported in such period or even resulting in a loss being reported for such period.

The dangers inherent in our operations and the limits on insurance coverage could expose us to potentially significant liability costs and materially interfere with the performance of our operations.

Our operations are subject to numerous operating risks inherent in the oil and gas industry that could result in substantial losses. These risks include the following:

- fires;
- explosions, blowouts and cratering;
- hurricanes and other extreme weather conditions;
- mechanical problems, including pipe failure;
- abnormally pressured formations; and
- environmental accidents, including oil spills, gas leaks or ruptures, uncontrollable flows of oil, gas, brine or well fluids, or other discharges of toxic gases or other pollutants.

Our liftboats and marine vessels are also subject to operating risks such as catastrophic marine disasters, adverse weather conditions, collisions and navigation errors.

The occurrence of these risks could result in substantial losses due to personal injury, loss of life, damage to or destruction of wells, production facilities or other property or equipment, or damages to the environment. In addition, certain of our employees who perform services on offshore platforms and marine vessels are covered by provisions of the Jones Act, the Death on the High Seas Act and general maritime law. These laws make the liability limits established by federal and state workers compensation laws inapplicable to these employees and instead permit them or their representatives to pursue actions against us for damages for job related injuries. In such actions, there is generally no limitation on our potential liability.

Any litigation arising from a catastrophic occurrence involving our services or equipment could result in large claims for damages. The frequency and severity of such incidents affect our operating costs, insurability and relationships with customers, employees and regulators. Any increase in the frequency or severity of such incidents, or the general level of compensation awards with respect to such incidents, could affect our ability to obtain insurance or projects from oil and gas companies. We maintain several types of insurance to cover liabilities arising from our services, including onshore and offshore non-marine operations, as well as marine vessel operations. These policies include primary and excess umbrella liability policies with limits of $100 million dollars per occurrence, including sudden and accidental pollution incidents. We also maintain property insurance on our physical assets, including marine vessels and operating equipment. Successful claims for which we are not fully insured may adversely affect our working capital and profitability.

The cost of many of the types of insurance coverage maintained by us has increased significantly during recent years and resulted in the retention of additional risk by us, primarily through higher insurance deductibles. Very few insurance underwriters offer certain types of insurance coverage maintained by us, and there can be no assurance that any particular type of insurance coverage will continue to be available in the future, that we will not accept retention of additional risk through higher insurance deductibles or otherwise, or that we will be able to purchase our desired level of insurance coverage at commercially feasible rates. Further, due to the losses as a result of hurricanes that occurred in the Gulf of Mexico in recent years, we were not be able to obtain insurance coverage comparable with that of prior years, thus putting us at a greater risk of loss due to severe weather conditions. In addition, costs have significantly increased for windstorm or hurricane coverage which also imposes higher deductibles and limits maximum aggregate recoveries. Any significant uninsured losses could have a material adverse effect on our financial position, results of operations and cash flows.

The occurrence of any of these risks could also subject us to clean-up obligations, regulatory investigation, penalties or suspension of operations. Further, our operations may be materially curtailed, delayed or canceled as a result of numerous factors, including the following:

- the presence of unanticipated pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in obtaining equipment or in the delivery of equipment and services.

We are vulnerable to the potential difficulties associated with rapid expansion.

We have grown rapidly over the last several years through internal growth and acquisitions of other companies. We believe that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on our management personnel. The following factors could present difficulties to us:

- lack of sufficient executive-level personnel;
- increased administrative burden; and
- increased logistical problems common to large, expansive operations.

If we do not manage these potential difficulties successfully, our operating results could be adversely affected.

Our inability to control the inherent risks of acquiring businesses could adversely affect our operations.

Acquisitions have been and we believe will continue to be a key element of our business strategy. We cannot assure you that we will be able to identify and acquire acceptable acquisition candidates on terms favorable to us in the future. We may be required to incur substantial indebtedness to finance future acquisitions. Such additional debt service requirements may impose a significant burden on our results of operations and financial condition. We cannot assure you that we will be able to successfully consolidate the operations and assets of any acquired business with our own business. Acquisitions may not perform as expected when the transaction was consummated and may be dilutive to our overall operating results. In addition, our management may not be able to effectively manage our increased size or operate a new line of business.

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The nature of our industry subjects us to compliance with regulatory and environmental laws.

Our business is significantly affected by a wide range of local, state and federal statutes, rules, orders and regulations relating to the oil and gas industry in general, and more specifically with respect to the environment, health and safety, waste management and the manufacture, storage, handling and transportation of hazardous wastes. The failure to comply with these rules and regulations can result in the revocation of permits, corrective action orders, administrative or civil penalties and criminal prosecution. Further, laws and regulations in this area are complex and change frequently. Changes in laws or regulations, or their enforcement, could subject us to material costs.

Our operations are also subject to certain requirements under OPA. Under OPA and its implementing regulations, responsible parties, including owners and operators of certain vessels, are strictly liable for damages resulting from spills of oil and other related substances in the United States waters, subject to certain limitations. OPA also requires a responsible party to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Further, OPA imposes other requirements, such as the preparation of oil spill response plans. In the event of a substantial oil spill, we could be required to expend potentially significant amounts of capital which could have a material adverse effect on our future operations and financial results.

We have compliance costs and potential environmental liabilities with respect to our offshore and onshore operations, including our environmental cleaning services. Certain environmental laws provide for joint and several liabilities for remediation of spills and releases of hazardous substances. These environmental statutes may impose liability without regard to negligence or fault. In addition, we may be subject to claims alleging personal injury or property damage as a result of alleged exposure to hazardous substances. We believe that our present operations substantially comply with applicable federal and state pollution control and environmental protection laws and regulations. We also believe that compliance with such laws has not had a material adverse effect on our operations. However, we are unable to predict whether environmental laws and regulations will have a material adverse effect on our future operations and financial results. Sanctions for noncompliance may include revocation of permits, corrective action orders, administrative or civil penalties and criminal prosecution.

Federal, state and local statutes and regulations require permits for plugging and abandonment and reports concerning operations. A decrease in the level of enforcement of such laws and regulations in the future would adversely affect the demand for our services and products. In addition, demand for our services is affected by changing taxes, price controls and other laws and regulations relating to the oil and gas industry generally. The adoption of laws and regulations curtailing exploration and development drilling for oil and gas in our areas of operations for economic, environmental or other policy reasons could also adversely affect our operations by limiting demand for our services. The regulatory burden on our business increases our costs and, consequently, affects our profitability. We are unable to predict the level of enforcement of existing laws and regulations, how such laws and regulations may be interpreted by enforcement agencies or court rulings, or whether additional laws and regulations will be adopted. We are also unable to predict the effect that any such events may have on us, our business or our financial condition.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflict may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to customers operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

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Regulation of greenhouse gas emissions effects and climate change issues may adversely affect our operations and markets.

The impact and implication of greenhouse gas emissions has received increasing attention, especially in the form of proposals to regulate the emissions. Regulation of emissions has been proposed on an international, national, regional, state and local level. These proposals include an international protocol, which has gone into effect but is not binding on the United States, and numerous bills introduced to the U.S. Congress relating to climate change.

In June 2009, a bill to control and reduce emissions of greenhouse gasses in the United States, was approved by the U.S. House of Representatives. The legislation, often referred to as a cap-and-trade system, would limit greenhouse gas emissions while creating a corresponding market for the purchase and sale of emission permits. Although not passed by the U.S. Senate, and therefore not law, the Senate has initiated drafting its own legislation for the control and reduction of greenhouse emissions.

It is not currently feasible to predict whether, or which of, the current greenhouse gas emission proposals will be adopted. In addition, there may be subsequent international treaties, protocols or accords that the United States joins in the future. The potential passage of climate change regulation may impact our operations, however, since it may limit demand and production of fossil fuels by our customers. The impact on our customers, in turn, may adversely affect demand for our products and services, which could adversely impact our operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information on properties is contained in Part I, Item 1 of this Form 10-K and in note 16 to our consolidated financial statements included in Part II, Item 8.

Item 3. Legal Proceedings

We are involved in various legal and other proceedings that are incidental to the conduct of our business. We do not believe that any of these proceedings, if adversely determined, would have a material adverse affect on our financial condition, results of operations or cash flows.

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

None.

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Item 4A. Executive Officers of Registrant

Terence E. Hall, age 64, has served as our Chairman of the Board and Chief Executive Officer and as a Director since December 1995. From December 1995 to November 2004, Mr. Hall also served as our President. Mr. Hall also serves as a member of the Board of Directors for Whitney Holding Corporation since December 2008.

Kenneth L. Blanchard, age 60, has served as our President since November 2004, and as our Chief Operating Officer since June 2002. Mr. Blanchard also served as one of our Executive Vice Presidents from December 1995 to November 2004.

Robert S. Taylor, age 55, has served as our Chief Financial Officer since January 1996, as one of our Executive Vice Presidents since September 2004, and as our Treasurer since July 1999. He also served as one of our Vice Presidents from July 1999 to September 2004.

A. Patrick Bernard, age 52, has served as our Senior Executive Vice President since July 2006 and as one of our Executive Vice Presidents since September 2004. He served as one of our Vice Presidents from June 2003 until September 2004. From July 1999 until June 2003, Mr. Bernard served as the Chief Financial Officer of our wholly-owned subsidiary International Snubbing Services, L.L.C. and its predecessor company.

Patrick C. Campbell, age 65, was appointed as one of our Executive Vice Presidents in April 2009. He has served as President and Chief Operating Officer of our wholly-owned subsidiary, Wild Well Control, Inc., since 2000. Mr. Campbell joined Wild Well Control in 1990 and served as its Executive Vice President until 2000.

L. Guy Cook, III, age 41, has served as one of our Executive Vice Presidents since September 2004. He has also served as an Executive Vice President of our wholly-owned subsidiary Superior Energy Services, L.L.C. since May 2006, and previously as a Vice President of this subsidiary and its predecessor company since August 2000. He served as our Director of Investor Relations from April 1997 to February 2000 and was also responsible for integrating our acquisitions during that time.

Charles M. Hardy, age 64, has served as one of our Executive Vice Presidents since January 2008. He has also served as Vice President and General Manager of our Marine Services division since May 2005, and previously as Vice President of Sales for this same division since August 2004. From July 2000 to July 2004, Mr. Hardy served as Vice President of Operations of Trico Marine Operators, Inc.

James A. Holleman, age 52, has served as one of our Executive Vice Presidents since September 2004. He served as one of our Vice Presidents from July 1999 to September 2004. Mr. Holleman has served as an Executive Vice President since May 2006, and previously as a Vice President since July 1999 of Superior Energy Services, L.L.C. From 1994 until July 1999, he served as the Chief Operating Officer of Cardinal Services, Inc., which we acquired in July 1999 and is the predecessor to Superior Energy Services, L.L.C.

William B. Masters, age 52, has served as our General Counsel and one of our Executive Vice Presidents since March 2008. He was previously a partner in the law firm Jones, Walker, Waechter, Poitevent, Carrère & Denègre L.L.P. for more than 20 years.

Danny R. Young, age 54, has served as one of our Executive Vice Presidents since September 2004. Since May 2006, Mr. Young has served as an Executive Vice President of Superior Energy Services, L.L.C. From January 2002 to May 2005, he served as Vice President of Health, Safety and Environment and Corporate Services of Superior Energy Services, L.L.C.

Patrick J. Zuber, age 49, has served as one of our Executive Vice Presidents since January 2008. Prior to joining us, he was employed with Weatherford International, Ltd. from June 1999 to December 2007, most recently serving as Vice President for the Middle East region since January 2007. From September 2005 to December 2007, Mr. Zuber served as Vice President for the Asia Pacific region. From March 2002 to August 2005, he served as General Manager for the Underbalanced Drilling Division for the Middle East and North Africa region.

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PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Common Stock Information

Our common stock trades on the New York Stock Exchange under the symbol SPN. The following table sets forth the high and low sales prices per share of common stock as reported for each fiscal quarter during the periods indicated.

	High	Low
2008		
First Quarter	$45.14	$34.90
Second Quarter	57.25	40.04
Third Quarter	54.42	29.95
Fourth Quarter	30.28	11.64
2009		
First Quarter	$18.37	$11.52
Second Quarter	24.19	12.97
Third Quarter	22.86	15.49
Fourth Quarter	25.78	20.14

As of February 18, 2010, there were 78,530,517 shares of our common stock outstanding, which were held by 173 record holders.

Dividend Information

We have never paid cash dividends on our common stock. We currently expect to retain all of the cash our business generates to fund the operation and expansion of our business and repurchase stock. In addition, the terms of our credit facility and the indenture governing our 6 7/8% unsecured senior notes due 2014 restrict our ability to pay dividends.

Equity Compensation Plan Information

Information required by this item with respect to compensation plans under which our equity securities are authorized for issuance is incorporated by reference from Part III, Item 12.

Issuer Purchases of Equity Securities

In December 2009, our Board of Directors approved a $350 million share repurchase program that will expire on December 31, 2011. There was no common stock repurchased and retired during the quarter ended December 31, 2009.

Performance Graph

The following performance graph and related information shall not be deemed solicitating material or filed with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, except to the extent that we specifically incorporate it by reference into such filing.

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The following graph compares the total stockholder return on our common stock for the last five years with the total return on the S&P 500 Stock Index and a Self-Determined Peer Group for the same period. The information in the graph is based on the assumption of a $100 investment on January 1, 2005 at closing prices on December 31, 2004. The comparisons in the graph are required by the Securities and Exchange Commission and are not intended to be a forecast or be indicative of possible future performance of our common stock.

Comparison of Cumulative Five Year Total Return

	Years Ended December 31,				
	2005	2006	2007	2008	2009
Superior Energy Services, Inc.	$137	$212	$223	$103	$158
S&P 500 Stock Index	$105	$121	$128	$ 81	$102
Peer Group	$152	$157	$213	$ 82	$134

NOTES:

The lines represent monthly index levels derived from compounded daily returns that include all dividends.

The indexes are reweighted daily, using the market capitalization on the previous trading day.

If the monthly interval, based on the fiscal year-end, is not a trading day, the preceding trading day is used.

The index level for all series was set to $100.00 on December 31, 2004.

Our Self-Determined Peer Group consists of the same peer group of eleven companies whose average stockholder return levels comprise part of the performance criteria established by the Compensation Committee under our long-term incentive compensation program: BJ Services Company, Helix Energy Solutions Group, Inc., Helmerich & Payne, Inc., Oceaneering International, Inc., Oil States International, Inc., Pride International, Inc., RPC, Inc., Seacor Holdings Inc., Smith International, Inc., Tetra Technologies, Inc., and Weatherford International, Ltd.

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Item 6. Selected Financial Data

We present below our selected consolidated financial data for the periods indicated. We derived the historical data from our audited consolidated financial statements.

The data presented below should be read together with, and are qualified in their entirety by reference to, Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements included elsewhere in this Annual Report on Form 10-K. The financial data is in thousands, except per share amounts.

	Years Ended December 31,				
	2009	2008	2007	2006	2005
Revenues	$1,449,300	$1,881,124	$1,572,467	$1,093,821	$ 735,334
Income (loss) from operations	(51,384)	565,692	465,838	316,889	125,603
Net income (loss)	(102,323)	351,475	271,558	187,663	67,859
Net income (loss) per share:					
Basic	(1.31)	4.39	3.35	2.35	0.87
Diluted	(1.31)	4.33	3.30	2.31	0.85
Total assets	2,516,665	2,490,145	2,255,295	1,872,067	1,097,250
Long-term debt, net	848,665	654,199	637,789	622,508	216,596
Decommissioning liabilities, less current portion			88,158	87,046	107,641
Stockholders equity	1,178,045	1,254,273	1,025,666	765,237	524,374

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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 and applicable notes to our consolidated financial statements and other information included elsewhere in this Annual Report on Form 10-K, including risk factors disclosed in Part I, Item 1A. 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 this Annual Report on Form 10-K.

Executive Summary

We believe we are a leading provider of oilfield services and equipment focused on serving the drilling-related needs of oil and gas companies primarily through our drilling products and services segment, and the production-related needs of oil and gas companies through our subsea and well enhancement and marine segments. In recent years, we have expanded geographically into select domestic land and international market areas. We also own oil and gas properties in the Gulf of Mexico that provide us additional opportunities for our subsea and well enhancement, decommissioning and platform management services.

During 2009, we renamed two of our segments in order to more accurately describe the markets and customers served by the businesses in each segment. The content of these segments has not changed. The financial performance of our various products and services are reported in four operating segments subsea and well enhancement (formerly well intervention), drilling products and services (formerly rental tools), marine and oil and gas.

Overview of our business segments

The subsea and well enhancement segment consists of specialized down-hole services, which are both labor and equipment intensive. We offer a wide variety of services used to maintain, enhance and extend oil and gas production from mature wells. In 2009, approximately 59% of this segment s revenue was derived from work performed in the Gulf of Mexico market area, while approximately 23% of segment revenue was from the domestic land market area and approximately 18% of segment revenue was from international market areas. While our income from operations as a percentage of segment revenue tends to be fairly consistent, special projects such as well control can directly increase our profitability.

The drilling products and services segment is capital intensive with higher operating margins as a result of relatively low operating expenses. The largest fixed cost is depreciation as there is little labor associated with our drilling products and services businesses. This segment s financial performance primarily is a function of changes in volume rather than pricing. In 2009, approximately 40% of segment revenue was derived from the Gulf of Mexico market area, while approximately 25% of segment revenue was from the domestic land market area and approximately 35% of segment revenue was from international market areas. Three rental products and their ancillary equipment accommodations, drill pipe and stabilization and other downhole equipment accounted for more than 90% of this segment s revenue in 2009.

The marine segment is comprised of our 26 rental liftboats. Operating costs of our liftboats are relatively fixed, and therefore, income from operations as a percentage of revenue can vary significantly from quarter to quarter and year to year based on changes in dayrates and utilization levels. Our activity levels can be severely impacted by harsh weather, especially during hurricane season.

Market drivers and conditions

The oil and gas industry remains highly cyclical and seasonal. Activity levels are driven primarily by traditional energy industry activity indicators, which include current and expected commodity prices, drilling rig counts, well completions and workover activity, geological characteristics of producing wells which determine the number of services required per well, oil and gas production levels, and customers spending allocated for drilling and production work, which is reflected in our customers operating expenses or capital expenditures.

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Historical market indicators are listed below:

	2009	% Change	2008	% Change	2007
Worldwide Rig Count [1]					
U.S.	1,089	-42%	1,879	6%	1,768
International [2]	997	-8%	1,079	7%	1,005
Commodity Prices (average)					
Crude Oil (West Texas Intermediate)	$62.67	-37%	$99.73	38%	$72.19
Natural Gas (Henry Hub)	$ 4.27	-53%	$ 9.04	4%	$ 8.67

(1) Estimate of drilling activity as measured by average active drilling rigs based on Baker Hughes Inc. rig count information.

(2) Excludes Canadian Rig Count.

As indicated by the table above, all major activity drivers declined sharply in 2009. The average number of drilling rigs working in the United States which is more weighted toward natural gas drilling than oil drilling declined 42%, while the international rig count which is more weighted toward oil drilling than natural gas drilling declined 8%. The average price of West Texas Intermediate crude oil decreased 37% from 2008, while the average price of natural gas at Henry Hub declined 53% from 2008.

Factors impacting our 2009 financial performance

The following table compares our revenues generated from major geographic regions for the years ended December 31, 2009 and 2008 (in thousands). We attribute revenue to countries based on the location where services are performed or the destination of the sale of products.

	2009	%	Revenue 2008	%	Change
Gulf of Mexico	$ 804,944	56%	$ 1,024,589	54%	$ (219,645)
U.S. Domestic Land	321,127	22%	539,795	29%	(218,668)
International	323,229	22%	316,740	17%	6,489
Total	$ 1,449,300	100%	$ 1,881,124	100%	$ (431,824)

The significant downturn in commodity prices, the drilling rig count and overall industry activity reduced pricing and utilization of our products and services in all segments and geographic markets, especially in North America, where our domestic land revenue decreased 41% to $321.1 million. In this market, we experienced a 42% decrease in revenue from our drilling products and services segment and a 40% decrease in revenue from our subsea and well enhancement segment. Within individual product/service lines, the largest declines in the domestic land market areas were in coiled tubing, cased hole wireline, well control, rentals of accommodations and rentals and sales of stabilizers and related equipment.

Our Gulf of Mexico revenue declined 21% to $804.9 million due to (1) the aforementioned industry downturn; (2) reduced revenue on our large-scale decommissioning project; and , (3) the March 2008 sale of 75% of our interest in SPN Resources, our oil and gas production subsidiary which contributed $55 million in revenue in 2008.

Our international revenue increased 2% to $323.2 million due primarily to a project in Mexico involving one of our 245-ft. class liftboats. International revenue in our subsea and well enhancement segment increased 11% as we started three projects off the coast of Angola and experienced increased demand for emergency well control work in West Africa. This increase was offset by a 10% decrease in revenue from our drilling products and services segment primarily due to a decrease in drill pipe rentals in the North Sea and rentals of stabilization equipment in international markets.

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Industry Outlook

The weak industry conditions that prevailed throughout much of 2009 are showing signs of stabilizing. Domestic drilling rig count and oil and natural gas prices have steadily increased towards the end of 2009. However, there is still much uncertainty regarding overall demand for oilfield products and services. As a result, we anticipate utilization for many of our products and services to increase in 2010. Pricing could increase as the year progresses and will depend on utilization of our assets and continued improvement in industry fundamentals.

While the worst of the domestic and global financial crisis appears to be over, the U.S. economy has yet to show strong enough growth to spur significant increases in industrial demand for hydrocarbons, particularly natural gas, which is a major driver of domestic oilfield activity. Low industrial demand coupled with persistently high supplies of domestic natural gas make it difficult to forecast the pace of increases in our activity. In addition, changes in demand for our products and services tend to lag changes in the drilling rig count.

Our response to market conditions has been to reduce headcount in certain geographic markets without impairing our ability to participate in an increase in demand once industry conditions improve, move assets to other geographic markets, consolidate certain facilities and reduce operating costs. In addition, we continue to pursue new growth initiatives through acquisitions. In January 2010, we acquired both Hallin Marine Subsea International Plc, an international provider of integrated subsea services and engineering solutions, and a 51% interest in the Gulf of Mexico-based Bullwinkle platform and related oil and gas assets from Shell Offshore Inc., which provides us an opportunity to use our services to produce the field s remaining oil and gas reserves, plug and abandon the property s 29 wells and decommission the platform once the field reaches the end of its economic life. The Bullwinkle platform will also generate revenue from production handling agreements which will be recorded in our subsea and well enhancement segment.

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, long-term construction accounting and self insurance. 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 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 used in operations when the fair value of those assets is less than their respective carrying amount. Fair value is measured, in part, by the estimated cash flows to be generated by those assets. Our cash flow estimates are based upon, among other things, historical results adjusted to reflect our best estimate of future market rates, utilization levels and operating performance. 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. Assets are grouped by subsidiary or division for the impairment testing, except for liftboats, which are grouped together by leg length. These groupings represent the lowest level of identifiable cash flows. We have long-lived assets, such as facilities, utilized by multiple operating divisions that do not have identifiable cash flows. Impairment testing for these long-lived assets is based on the consolidated entity. Assets to be disposed of are reported at the lower of the carrying amount or fair value less estimated costs to sell. Our estimate of fair value represents our best

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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 a significant impact on the carrying value of these assets and, in periods of prolonged down cycles, may result in impairment charges.

During the second quarter of 2009, we recorded approximately $92.7 million of impairment expense in connection with our intangible assets within our subsea and well enhancement segment. This reduction in value of intangible assets is primarily due to the decline in demand for services in the domestic land markets. During the fourth quarter of 2009, the domestic land markets remained depressed and our forecast of this market did not suggest a timely recovery sufficient to support our current carrying values. As such, we recorded approximately $119.8 million of impairment expense related to our tangible assets (property, plant and equipment) within the same segment (see note 3 to our consolidated financial statements included in Part II, Item 8).

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. We test goodwill for impairment in accordance with Accounting Standard Codification 350-10 (ASC 350-10), Intangibles Goodwill and Other. ASC 350-10 requires that goodwill as well as other intangible assets with indefinite lives not be amortized, but instead tested annually for impairment. Our annual testing of goodwill is based on carrying value and our estimate of fair value at December 31. We estimate the fair value of each of our reporting units (which are consistent with our business segments) using various cash flow and earnings projections discounted at a rate estimated to approximate the reporting units weighted average cost of capital. 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.

Based on business conditions and market values that existed at December 31, 2009, we concluded that no goodwill impairment loss was required. Even though we recognized a $212.5 million impairment of long-lived assets within the subsea and well enhancement segment during 2009, the estimated future cash flows, used in the fair value calculation of this segment, from our Gulf of Mexico and international markets more than offset the depressed land markets.

If, among other factors, (1) our market capitalization declines or remains below our stockholders equity, (2) the fair value of our reporting units decline, or (3) the adverse impacts of economic or competitive factors are worse than anticipated, we could conclude in future periods that impairment losses are required in order to reduce the carrying value of our goodwill and long-lived assets. Depending on the severity of the changes in the key factors underlying the valuation of our reporting units, such losses could be significant.

Income Taxes. We use the asset and liability method of accounting for income taxes. This method 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 the rate is enacted.

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 the customer s creditworthiness known to us. In addition, we record a reserve based on the size and age of all receivable balances against those balances that do not have specific reserves. If the financial condition of our customers deteriorates, resulting in their inability to make payments, additional allowances may be required.

Revenue Recognition. Our products and services are generally sold based upon purchase orders or contracts with customers that include fixed or determinable prices. We recognize revenue when services or equipment are provided and collectibility is reasonably assured. We contract for marine, subsea and well enhancement and environmental projects either on a day rate or turnkey basis, with a majority of our projects conducted on a day rate basis. The products we rent within our drilling products and services segment are rented on a day rate basis, and revenue from the sale of equipment is recognized when the equipment is shipped. We use the percentage-of- completion method for recognizing our revenues and related costs on our contract to decommission seven downed oil and gas platforms and related well facilities located in the Gulf of Mexico. We estimate the percentage complete utilizing costs incurred as a percentage of total estimated costs.

During the fourth quarter of 2009 as the project to decommission seven downed oil and gas platforms and well facilities neared completion, we determined it was necessary to increase the total cost estimate due to various well conditions and other technical issues associated with this complex and challenging project (see note 5 to our consolidated financial statements included in Part II, Item 8).

Long-Term Construction Accounting for Revenue and Profit (Loss) Recognition. A portion of our revenue is derived from long-term contracts. For contracts that meet the criteria under Accounting Standards Codification 605-35, Construction-Type and Production-Type Contracts, we recognize revenues on the percentage-of-completion method, primarily based on costs incurred to date compared with total estimated contract costs. It is possible there will be future and currently unforeseeable significant adjustments to our estimated contract revenues, costs and profitability for contracts currently in process. These adjustments could, depending on the magnitude of the adjustments, materially, positively or negatively, affect our operating results in an annual or quarterly reporting period. To the extent that an adjustment in the estimated total contract cost impacts estimated profit of the contract, the cumulative change to revenue and profitability is reflected in the period in which this adjustment in estimate is identified. The accuracy of the revenue and estimated earnings we report for fixed-price contracts is dependent upon the judgments we make in estimating our contract performance and contract revenue and costs.

Self Insurance. We self insure, through deductibles and retentions, up to certain levels for losses related to workers compensation, third party liability insurances, property damage, and group medical. With our growth, 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 actuarial reviews of 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 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 insurance coverage, we cannot assure that such coverage will adequately protect us against liability from all potential consequences.

Comparison of the Results of Operations for the Years Ended December 31, 2009 and 2008

For the year ended December 31, 2009, our revenue was $1,449.3 million and our net loss was $102.3 million, or $1.31 loss per share. Included in the results for the year ended December 31, 2009 were non-cash, pre-tax charges of $212.5 million for the reduction in value of assets within our subsea and well enhancement segment and $36.5 million for the reduction in value of our remaining equity-method investment in Beryl Oil and Gas L.P. (BOG). Also included in the results for the year ended December 31, 2009 were losses of $18.0 million from our share of equity-method investments and $4.6 million of other non-cash charges related to SPN Resources. For the year ended December 31, 2008, revenue was $1,881.1 million, and net income was $351.5 million or $4.33 diluted earnings per share. Net income for the year ended December 31, 2008 included a $40.9 million gain from the sale of businesses. Revenue across all segments was lower in 2009 as compared to 2008 as a result of the significant downturn in commodity prices, the drilling rig count and overall industry activity. Revenue in our oil and gas segment decreased due the fact that we sold 75% of our interest in SPN Resources in March 2008. SPN Resources represented substantially all of our operating oil and gas segment. Subsequent to the sale of our interest on March 14, 2008, we account for our remaining interest in SPN Resources using the equity-method.

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The following table compares our operating results for the years ended December 31, 2009 and 2008 (in thousands). Cost of services, rentals and sales excludes depreciation, depletion, amortization and accretion for each of our business segments. Oil and gas eliminations represent products and services provided to the oil and gas segment by our other segments.

	Revenue			Cost of Services, Rentals and Sales				
	2009	2008	Change	2009	%	2008	%	Change
Subsea and Well Enhancement	$ 919,335	$ 1,155,221	$ (235,886)	$ 616,116	67%	$ 633,127	55%	$ (17,011)
Drilling Products and Services	426,876	550,939	(124,063)	143,802	34%	178,563	32%	(34,761)
Marine	103,089	121,104	(18,015)	64,116	62%	74,830	62%	(10,714)
Oil and Gas		55,072	(55,072)			12,986	24%	(12,986)
Less: Oil and Gas Elim		(1,212)	1,212			(1,212)		1,212
Total	$ 1,449,300	$ 1,881,124	$ (431,824)	$ 824,034	57%	$ 898,294	48%	$ (74,260)

The following discussion analyzes our results on a segment basis.

Subsea and Well Enhancement Segment (formerly Well Intervention Segment)

Revenue for our subsea and well enhancement segment was $919.3 million for the year ended December 31, 2009, as compared to $1,155.2 million for 2008. Cost of services increased to 67% of segment revenue in 2009, as compared to 55% of segment revenue in 2008. Our revenue decreased 20% due to a $139.5 million decrease in our domestic land business as a result of the significant downturn in commodity prices, the drilling rig count and overall industry activity in North America. Additionally, our revenue from a large-scale platform decommissioning project decreased approximately 29% due to the combination of less work being performed coupled with an increase in the estimated total cost of this project. During the fourth quarter of 2009 as we neared completion of this project, we determined it was necessary to increase our total cost estimate due to various well conditions and other technical issues associated with this complex and challenging project. As the revenue related to this long-term contract is recorded on the percentage-of-completion method utilizing costs incurred as a percentage of total estimated costs, the cumulative effect of changes to estimated total contract costs is recognized in the period in which revisions are identified. Revenue from international markets grew 11% in 2009 due to an increase in emergency well control work and the commencement of three projects off the coast of Angola.

Drilling Products and Services Segment (formerly Rental Tools)

Revenue for our drilling products and services segment was $426.9 million for the year ended December 31, 2009, an approximate 23% decrease from 2008. Cost of services increased to 34% of segment revenue in 2009 from 32% in 2008. The decrease in drilling products and services revenue is primarily related to a decrease in the rentals of our on-site accommodation units and stabilization equipment, specifically in the domestic land market, and rentals of our drill pipe and stabilization equipment in international markets. Drilling products and services revenue in our domestic land markets decreased 42% to approximately $108.4 million in 2009 from 2008. Additionally, drilling products and services revenue generated from the Gulf of Mexico and international markets decreased by 14% and 10%, respectively, in 2009 from 2008.

Marine Segment

Our marine segment revenue for the year ended December 31, 2009 decreased 15% from 2008 to $103.1 million. Cost of services as a percentage of revenue remained constant at 62% in 2009 and 2008. The fleet s average utilization decreased to approximately 52% in 2009 from 66% in 2008. The utilization decrease was offset by an increase in the fleet s average dayrate, which increased 8% to approximately $16,800 in 2009 from $15,600 in 2008. The increase in average dayrate was primarily due to the addition of two 265-ft. class vessels in the second quarter of 2009. Generally, cost of services does not fluctuate proportionately with revenue due to the high fixed costs associated with this segment; thus, a decrease in revenue would typically result in higher cost of service as a percentage of revenue. However, during 2008, we incurred substantial costs for maintenance to our liftboat fleet. Additionally, we benefited from a decrease in insurance expense in 2009 as a result of our favorable loss history and more competitive marine insurance markets.

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In the fourth quarter of 2009, our two 265-ft. class liftboats were removed from service following damage to one of the vessels during Hurricane Ida. One vessel is expected to return to service by the second quarter of 2010 and the other in the third quarter of 2010. Additionally, we sold four liftboats from our 145 155-ft. class for approximately $7.7 million and recorded a gain of approximately $2.1 million.

Oil and Gas Segment

In March 2008, we sold 75% of our interest in SPN Resources for approximately $167.2 million and recorded a pre-tax gain on sale of this business of approximately $37.1 million. SPN Resources represented substantially all of our oil and gas segment. Subsequent to the sale of our interest on March 14, 2008, we account for our remaining interest in SPN Resources using the equity-method.

Depreciation, Depletion, Amortization and Accretion

Depreciation, depletion, amortization and accretion increased to $207.1 million for the year ended December 31, 2009 from $175.5 million in 2008. Depreciation and amortization expense related to our subsea and well enhancement segment increased $17.8 million, or 25%, in 2009 from the same period in 2008. The increase in depreciation and amortization expense for this segment is primarily attributable to our 2009 and 2008 capital expenditures partially offset by a decrease in the amortization expense as a result of a $92.7 million reduction in the value of amortizable intangible assets in the second quarter of 2009. Depreciation and amortization expense related to our drilling products and services segment increased $15.2 million, or 17%, in 2009 from the same period in 2008 primarily due to our 2009 and 2008 capital expenditures. Depreciation expense related to the marine segment in 2009 increased approximately $1.4 million, or 14%, from 2008. The increase in depreciation expense for the marine segment is primarily attributable to the delivery of two new vessels, which was partially offset by lower utilization.

General and Administrative Expenses

General and administrative expenses decreased to $259.1 million for the year ended December 31, 2009 from $282.6 million in 2008. General and administrative expenses related to our subsea and well enhancement and drilling products and services segments decreased $21.8 million, or 8%, from 2008 to 2009. The decrease in general and administrative expense within these two segments is primarily related to decreased incentive compensation expenses. General and administrative expenses related to our marine segment increased $7.1 million primarily due to the expense incurred as a result of the write-down of components from one of our 265-ft. class liftboats in the fourth quarter of 2009.

Reduction in Value of Assets

During the second quarter of 2009, we recorded an expense of approximately $92.7 million in connection with intangible assets within our subsea and well enhancement segment. This reduction in value of intangible assets is primarily due to the decline in demand for services in the domestic land markets. During the fourth quarter of 2009, the domestic land markets remained depressed and our forecast of this market did not suggest a timely recovery sufficient to support our current carrying values. As such, we recorded an expense of approximately $119.8 million related to our tangible assets (property, plant and equipment) within the same segment.

Additionally, we recorded a $36.5 million expense to write off our remaining investment in BOG, an equity-method investment in which we owned a 40% interest. In April 2009, BOG defaulted under its loan agreements due primarily to the impact of production curtailments from Hurricanes Gustav and Ike in 2008 and the decline of natural gas and oil prices. As a result of continued negative BOG operating results, lack of viable interested buyers and unsuccessful attempts to renegotiate the terms and conditions of BOG s loan agreements, we wrote off the remaining carrying value of our investment in BOG.

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Comparison of the Results of Operations for the Years Ended December 31, 2008 and 2007

For the year ended December 31, 2008, our revenue was $1,881.1 million, resulting in net income of $351.5 million or $4.33 diluted earnings per share. The results included a pre-tax gain of $40.9 million from the sale of businesses. For the year ended December 31, 2007, revenue was $1,572.5 million, and net income was $271.6 million or $3.30 diluted earnings per share. Net income for the year ended December 31, 2007 included a pre-tax gain of $7.5 million from the sale of a non-core drilling products and services business. Net income for the years ended December 31, 2008 and 2007 include additional non-cash interest expense of $16.3 million and $15.2 million, respectively, as we retrospectively adopted Accounting Standards Codification 470-20, Debt with Conversion and Other Options that required the proceeds from the issuance of our 1.50% senior exchangeable notes to be allocated between a liability component and an equity component. The resulting debt discount is amortized over the period the exchangeable debt is expected to be outstanding as additional non-cash interest expense. Revenue in the subsea and well enhancement segment was higher primarily as a result of an increase in engineering and project management services associated with a large-scale platform decommissioning project. Revenue in the drilling products and services segment was higher as a result of increased production-related projects and drilling activity worldwide, recent acquisitions and continued expansion of our drilling products and services business. Both revenue and income from operations decreased in our marine segment due to lower utilization and dayrates. Revenue in our oil and gas segment decreased due the fact that we sold 75% of our interest in SPN Resources in March 2008. SPN Resources represented substantially all of our operating oil and gas segment. Subsequent to the sale of our interest on March 14, 2008, we account for our remaining interest in SPN Resources using the equity-method.

The following table compares our operating results for the years ended December 31, 2008 and 2007 (in thousands). Cost of services, rentals and sales excludes depreciation, depletion, amortization and accretion for each of our business segments. Oil and gas eliminations represent products and services provided to the oil and gas segment by our other segments.

The following discussion analyzes our results on a segment basis.

Subsea and Well Enhancement Segment (formerly Well Intervention)

Revenue for our subsea and well enhancement segment was $1,155.2 million for the year ended December 31, 2008, as compared to $761.0 million for 2007. Cost of services remained constant at 55% of segment revenue in 2008 and 2007. Our revenue increased 53% as the result of our performance on a large-scale platform decommissioning project. We also experienced an increase in revenue from a full year of expansion of wireline and snubbing services in Continental Europe. Additionally, revenue from coiled tubing services increased approximately 37% mainly from additional activity and the addition of new equipment in domestic land market areas. These increases were offset by a decrease in revenue from the completion of a construction contract for the sale of a derrick barge in June 2008. We recognized revenue for this construction contract throughout 2007 using the percentage-of-completion method. Revenue from land and international market areas grew 9% and 11%, respectively, in 2008.

Drilling Products and Services Segment (formerly Rental Tools)

Revenue for our drilling products and services segment was $550.9 million for the year ended December 31, 2008, an approximate 11% increase from the same period in 2007. Cost of services remained constant at 32% of segment revenue in 2008 and 2007. Our largest increases in revenue were generated from our stabilizers and on-site accommodations. These increases were partially offset by the loss of revenue from the sale of a non-core rental business in 2007. Our largest geographic revenue improvements were in the Gulf of Mexico where revenue increased 27% to approximately $197.3 million in 2008 over the same period in 2007. We also experienced significant increases in the South American and African market areas. These increases were partially offset by a decrease in drill pipe rental in the North Sea market.

Marine Segment

Our marine segment revenue for the year ended December 31, 2008 decreased 5% from 2007 to $121.1 million. Conversely, cost of services increased 24% for the year ended December 31, 2008, from the same period in 2007, due to lower utilization, increased maintenance and higher direct costs. The increase in maintenance cost is partially due to the fact that we use periods of lower utilization as an opportunity to perform required maintenance to our liftboat fleet. Additionally, cost of services usually does not fluctuate proportionately with revenue due to the high fixed costs associated with this segment. The fleet s average utilization decreased to approximately 66% in 2008 from 71% in 2007. The fleet s average dayrate decreased 10% to approximately $15,600 in 2008 from $17,300 in 2007.

Oil and Gas Segment

In March 2008, we sold 75% of our interest in SPN Resources for approximately $167.2 million and recorded a pre-tax gain on sale of this business of approximately $37.1 million. SPN Resources represented substantially all of our oil and gas segment. Subsequent to the sale of our interest on March 14, 2008, we account for our remaining interest in SPN Resources using the equity-method.

Depreciation, Depletion, Amortization and Accretion

Depreciation, depletion, amortization and accretion decreased to $175.5 million for the year ended December 31, 2008 from $187.8 million in 2007. Depreciation, depletion and accretion for our oil and gas segment decreased $56.4 million, or 95%, in 2008 from 2007. As a result of the sale of our 75% interest in SPN Resources on March 14, 2008, we ceased the depreciation and depletion for this segment when these assets were identified as available for sale in January 2008. Depreciation and amortization expense related to our subsea and well enhancement and drilling products and services segments for 2008 increased by $42.8 million, or 35%, from 2007. The increase in depreciation and amortization expense for these segments is primarily attributable to our 2008 and 2007 capital expenditures. Depreciation expense related to the marine segment in 2008 increased approximately $1.2 million, or 14%, from 2007. The increase in depreciation expense for the marine segment is primarily attributable to the delivery of two new vessels, which was partially offset by lower utilization.

General and Administrative Expenses

General and administrative expenses increased to $282.6 million for the year ended December 31, 2008 from $228.1 million in 2007. General and administrative expenses related to our subsea and well enhancement and drilling products and services segments increased $55.1 million, or 27%, from 2007 to 2008. The increase in general and administrative expense is primarily related to increased expenses associated with our geographic expansion, increased retirement benefits, increased incentive compensation expenses due to our strong operating results and additional infrastructure to enhance our growth. General and administrative expenses remained constant at approximately 15% of revenue for 2008 and 2007.

Liquidity and Capital Resources

In the year ended December 31, 2009, we generated net cash from operating activities of $276.1 million as compared to $402.4 million in 2008. The decrease in cash generated from operating activities is primarily due to the overall decrease in sales and profitability from 2008 to 2009. Our primary liquidity needs are for working capital, capital expenditures, acquisitions and debt service. Our primary sources of liquidity are cash flows from operations and borrowings under our revolving credit facility. We had cash and cash equivalents of $206.5 million at December 31, 2009 compared to $44.9 million at December 31, 2008. As of December 31, 2009, $167.1 million was held in a foreign account in anticipation of the January 2010 acquisition of Hallin.

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We spent $286.3 million of cash on capital expenditures during the year ended December 31, 2009. Approximately $124.8 million was used to expand and maintain our drilling products and services equipment inventory, approximately $61.9 million was spent on our marine segment and approximately $99.6 million was used to expand and maintain the asset base of our subsea and well enhancement segment.

In April 2008, we contracted to purchase a 50% interest in four 265-ft. class liftboats. The first two vessels were placed in service during April and May of 2009. In September 2009, we acquired the other 50% interest in the four liftboats for a total price of $38.1 million, following the other owner s exercise of an option requiring us to purchase its interest in these liftboats. Construction on the two remaining vessels was suspended in March 2009, as a result of disputes with the builder. Those disputes have been resolved and the uncompleted vessels have been delivered to a different shipyard to be completed. We expect the remaining two vessels to be completed during the second half of 2011.

In May 2009, we amended our revolving credit facility to increase the borrowing capacity to $325 million from $250 million. Any amounts outstanding under the revolving credit facility are due on June 14, 2011. Costs incurred during the year ended December 31, 2009 associated with amending the revolving credit facility were approximately $2.3 million. These costs were capitalized and are being amortized over the remaining term of the credit facility. At February 18, 2010, we had approximately $188.6 million outstanding under the bank credit facility. Additionally, we had approximately $9.5 million of letters of credit outstanding, which reduces our borrowing capacity under this credit facility. Borrowings under the credit facility bear interest at a LIBOR rate plus margins that depend on our leverage ratio. Indebtedness under the credit facility is secured by substantially all of our assets, including the pledge of the stock of our principal subsidiaries. The credit facility contains customary events of default and requires that we satisfy various financial covenants. It also limits our ability to pay dividends or make other distributions, make acquisitions, create liens or incur additional indebtedness.

We have $14.2 million outstanding at December 31, 2009 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 June 3rd and December 3rd of each year through the maturity date of 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, working capital and debt-to-equity requirements.

The Company s current long-term issuer credit rating is BB+ by Standard and Poor s and Ba3 by Moody s. Our credit rating may be impacted by the rating agencies view of the cyclical nature of our industry sector.

We have outstanding $300 million of 6 7/8% unsecured senior notes due 2014. The indenture governing the senior notes requires semi-annual interest payments on June 1st and December 1st of each year through the maturity date of June 1, 2014. The indenture contains certain covenants that, among other things, limit us from incurring additional debt, repurchasing capital stock, paying dividends or making other distributions, incurring liens, selling assets or entering into certain mergers or acquisitions.

We also have outstanding $400 million of 1.50% senior exchangeable notes due 2026. The exchangeable notes bear interest at a rate of 1.50% per annum and decrease to 1.25% per annum on December 15, 2011. Interest on the exchangeable notes is payable semi-annually in arrears on December 15th and June 15th of each year through the maturity date of December 15, 2026. The exchangeable notes do not contain any restrictive financial covenants. Under certain circumstances, holders may exchange the notes for shares of our common stock. The initial exchange rate is 21.9414 shares of common stock per $1,000 principal amount of notes. This is equal to an initial exchange price of $45.58 per share. The exchange price represents a 35% premium over the closing share price at the date of issuance. The notes may be exchanged under the following circumstances:

- during any fiscal quarter (and only during such fiscal quarter), if the last reported sale price of our common stock is greater than or equal to 135% of the applicable exchange price of the notes for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter;

prior to December 15, 2011, during the five business-day period after any ten consecutive trading-day period (the measurement period) in which the trading price of $1,000 principal amount of notes for each trading day in the measurement period was less than 95% of the product of the last reported sale price of our common stock and the exchange rate on such trading day;

if the notes have been called for redemption;

upon the occurrence of specified corporate transactions; or

at any time beginning on September 15, 2026, and ending at the close of business on the second business day immediately preceding the maturity date of December 15, 2026.

In connection with the issuance of the exchangeable notes, we entered into agreements with affiliates of the initial purchasers to purchase call options and sell warrants on our common stock. We may exercise the call options we purchased at any time to acquire approximately 8.8 million shares of our common stock at a strike price of $45.58 per share. The owners of the warrants may exercise the warrants to purchase from us approximately 8.8 million shares of our common stock at a price of $59.42 per share, subject to certain anti-dilution and other customary adjustments. The warrants may be settled in cash, in common stock or in a combination of cash and common stock, at our option. These transactions may potentially reduce the dilution of our common stock from the exchange of the notes by increasing the effective exchange price to $59.42 per share. Lehman Brothers OTC Derivatives, Inc. (LBOTC) is the counterparty to 50% of our call option and warrant transactions. In October 2008, LBOTC filed for bankruptcy protection. We continue to carefully monitor the developments affecting LBOTC. Although we may not be able to retain the benefit of the call option due to LBOTC s bankruptcy, we do not expect that there will be a material impact, if any, on the financial statements or results of operations. The call option and warrant transactions described above do not affect the terms of the outstanding exchangeable notes.

The following table summarizes our contractual cash obligations and commercial commitments at December 31, 2009 (amounts in thousands) for our long-term debt (including estimated interest payments), operating leases and other long-term liabilities. We do not have any other material obligations or commitments.

Description	2010	2011	2012	2013	2014	Thereafter
Long-term debt, including estimated interest payments	$37,259	$209,319	$27,231	$27,179	$316,814	$474,354
Operating leases	13,191	7,609	4,609	2,654	2,221	14,434
Other long-term liabilities		16,647	10,103	6,948	4,544	14,281
Total	$50,450	$233,575	$41,943	$36,781	$323,579	$503,069

We currently believe that we will spend approximately $250 million on capital expenditures, excluding acquisitions, during 2010. 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.

On January 26, 2010, we acquired 100% of the equity interest of Hallin, for approximately $162.3 million of cash. Prior to December 31, 2009, we had borrowed approximately $169.8 million under our revolving credit facility in order to fund the acquisition. These funds were held in an escrow account at December 31, 2009. In conjunction with the acquisition, the Company repaid approximately $55.2 million of Hallin s debt. Hallin is an international provider of integrated subsea services and engineering solutions, focused on installing, maintaining and extending the life of subsea wells. Hallin operates in international offshore oil and gas markets with offices and facilities located in Singapore; Jakarta, Indonesia; Perth, Australia; Aberdeen, Scotland; and Houston, Texas.

We anticipate collecting approximately $280 million for the remainder of 2010 in connection with the large-scale platform decommissioning project in the Gulf of Mexico. During January 2010, we collected approximately $69 million related to this project.

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 fund capital expenditures required to implement our growth strategy with 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.

Off-Balance Sheet Arrangements

We have no off-balance sheet financing arrangements other than the potential additional consideration that may be payable as a result of the future operating performances of our acquisitions. At December 31, 2009, the maximum additional consideration payable for these acquisitions was approximately $26.3 million. Since these acquisitions occurred before the adoption of Accounting Standards Codification 805-10, Business Combinations, these amounts are not classified as liabilities 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.

Hedging Activities

We enter into forward foreign exchange contracts to mitigate the impact of foreign currency fluctuations. The forward foreign exchange contracts we enter into generally have maturities ranging from one to eighteen months. We do not enter into forward foreign exchange contracts for trading purposes. During the year ended December 31, 2009, we held outstanding foreign currency forward contracts in order to hedge exposure to currency fluctuations between the British Pound Sterling and the Euro. These contracts were not accounted for as hedges and were marked to fair market value each period. As of December 31, 2009, we had no outstanding foreign currency forward contracts.

Recently Issued Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board issued Accounting Standards Update No. 2009-01 (ASC Topic 105), Generally Accepted Accounting Principles, which establishes the FASB Accounting Standards Codification (the Codification or ASC) as the official single source of authoritative U.S. generally accepted accounting principles (GAAP). All existing accounting standards are superseded. All other accounting guidance not included in the Codification is considered non-authoritative. The Codification also includes all relevant Securities and Exchange Commission guidance organized using the same topical structure in separate sections within the Codification. Following the Codification, the Board will not issue new standards in the form of Statements, FASB Staff Positions or Emerging Issues Task Force Abstracts. Instead, it will issue Accounting Standards Updates which will serve to update the Codification, provide background information about the guidance and provide the basis for conclusions on the changes to the Codification. The Codification is not intended to change GAAP, but it changes the way GAAP is organized and presented. The Codification is effective for financial statements issued for interim and annual periods ending after September 15, 2009 and the principal impact on our financial statements is limited to disclosures as all current and future references to authoritative accounting literature will be referenced in accordance with the Codification.

In June 2009, the Financial Accounting Standards Board issued its Accounting Standards Codification 810-10 (ASC 810-10), Amendments to FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities, for determining whether an entity is a variable interest entity (VIE) and requires an enterprise to perform an analysis to determine whether the enterprise s variable interest or interests give it a controlling financial interest in a VIE. ASC 810-10 also requires ongoing assessments of whether an enterprise is the primary beneficiary of a VIE, requires enhanced disclosures and eliminates the scope exclusion for qualifying special-purpose entities. ASC 810-10 is effective for annual reporting periods beginning after November 15, 2009. We are currently evaluating the impact the adoption of ASC 810-10 will have on our results of operations and financial position.

In October 2009, the Financial Accounting Standards Board issued Accounting Standards Update 2009-13 (ASU 2009-13), Multiple-Deliverable Revenue Arrangements. The new standard changes the requirements for establishing separate units of accounting in a multiple element arrangement and requires the allocation of arrangement consideration to each deliverable based on the relative selling price. The selling price for each deliverable is based on vendor-specific objective evidence (VSOE) if available, third-party evidence if VSOE is not available, or estimated selling price if neither VSOE or third-party evidence is available. ASU 2009-13 is effective for revenue arrangements entered into in fiscal years beginning on or after June 15, 2010. We are currently evaluating the impact the adoption of ASU 2009-13 will have on our results of operations and financial position.

In January 2010, the Financial Accounting Standards Board issued Accounting Standards Update 2010-06 (ASU 2010-06), Improving Disclosures about Fair Value Measurements. The update provides an amendment to ASC 820-10, Fair Value Measurements and Disclosures, requiring additional disclosures of significant transfers between Level 1 and Level 2 within the fair value hierarchy as well as information about purchases, sales, issuances and settlements using unobservable inputs (Level 3). ASU 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009 for new disclosures and clarifications of existing disclosures, except for disclosures about purchases, sales, issuances and settlements in the rollforward of activity in the Level 3 fair value measurements, which are effective for fiscal years beginning after December 15, 2010. We are currently evaluating the impact the adoption of ASU 2010-06 will have on our disclosures within our financial statements.

In January 2010, the Financial Accounting Standards Board issued Accounting Standards Update 2010-03 (ASU 2010-03), Oil and Gas Reserve Estimation and Disclosures. The update provides an amendment to Accounting Standards Codification 932 (ASC 932), Extractive Activities Oil and Gas, that expands the definition of oil- and gas-producing activities and requires disclosures of reserve quantities and standardized measure of cash flows for equity-method investments that have significant oil- and gas-producing activities. ASU 2010-03 is effective for annual reporting periods ending on or after December 31, 2009. ASU 2010-03 allows an entity that becomes subject to the disclosure requirements of ASC 932 due to the change to the definition of significant oil- and gas-producing activities to apply the disclosure provisions of ASC 932 in annual periods beginning after December 31, 2009. As such, we have elected to defer the application of ASU 2010-03 until our annual reporting period ended December 31, 2010. We are currently evaluating the impact the adoption of ASU 2010-03 will have on our disclosures within our financial statements.

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 our international operations, other than our operations in the United Kingdom and Europe, 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 derivatives for trading purposes or use derivatives with complex features. Assets and liabilities of our subsidiaries in the United Kingdom and Europe 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 (loss) in stockholders equity.

When we believe prudent, we enter into forward foreign exchange contracts to hedge the impact of foreign currency fluctuations. The forward foreign exchange contracts we enter into generally have maturities ranging from one to eighteen months. We do not enter into forward foreign exchange contracts for trading purposes. As of December 31, 2009, we had no outstanding foreign currency forward contracts.

Interest Rates

At December 31, 2009, $177.0 million of our long-term debt outstanding had variable interest rates. Based on the amount of this debt outstanding at December 31, 2009, a 10% increase in the variable interest rate would increase our interest expense for the year ended December 31, 2009 by approximately $528,000, while a 10% decrease would decrease our interest expense by approximately $528,000.

Equity Price Risk

We have $400 million of 1.50% senior exchangeable notes due 2026. The notes are, subject to the occurrence of specified conditions, exchangeable for our common stock initially at an exchange price of $45.58 per share, which would result in an aggregate of approximately 8.8 million shares of common stock being issued upon exchange. We may redeem for cash all or any part of the notes on or after December 15, 2011 for 100% of the principal amount redeemed. The holders may require us to repurchase for cash all or any portion of the notes on December 15, 2011, December 15, 2016 and December 15, 2021 for 100% of the principal amount of notes to be purchased plus any accrued and unpaid interest. The notes do not contain any restrictive financial covenants.

Each $1,000 of principal amount of the notes is initially exchangeable into 21.9414 shares of our common stock, subject to adjustment upon the occurrence of specified events. Holders of the notes may exchange their notes prior to maturity only if (1) the price of our common stock reaches 135% of the applicable exchange rate during certain periods of time specified in the notes; (2) specified corporate transactions occur; (3) the notes have been called for redemption; or (4) the trading price of the notes falls below a certain threshold. In addition, in the event of a fundamental change in our corporate ownership or structure, the holders may require us to repurchase all or any portion of the notes for 100% of the principal amount.

We also have agreements with affiliates of the initial purchasers to purchase call options and sell warrants of our common stock. We may exercise the call options at any time to acquire approximately 8.8 million shares of our common stock at a strike price of $45.58 per share. The owners of the warrants may exercise their warrants to purchase from us approximately 8.8 million shares of our common stock at a price of $59.42 per share, subject to certain anti-dilution and other customary adjustments. The warrants may be settled in cash, in shares or in a combination of cash and shares, at our option. Lehman Brothers OTC Derivatives, Inc. (LBOTC) is the counterparty to 50% of our call option and warrant transactions. In October 2008, LBOTC filed for bankruptcy protection. We continue to carefully monitor the developments affecting LBOTC. Although we may not be able to retain the benefit of the call option due to LBOTC s bankruptcy, we do not expect that there will be a material impact, if any, on the financial statements or results of operations. The call option and warrant transactions described above do not affect the terms of the outstanding exchangeable notes.

For additional discussion of the notes, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources in Part II, Item 7.

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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, 2009 and 2008, 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, 2009. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule, Valuation and Qualifying Accounts. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, 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.

As discussed in note 8 to the consolidated financial statements, the Company changed its method for accounting for debt with conversion and other options and, as discussed in note 4 to the consolidated financial statements, the Company changed its method of accounting for business combinations in 2009 due to the adoption of new accounting requirements issued by the FASB.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Superior Energy Services, Inc. s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2010 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

KPMG LLP
New Orleans, Louisiana
February 26, 2010

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Consolidated Balance Sheets
December 31, 2009 and 2008
(in thousands, except share data)

	2009	2008 *
ASSETS		
Current assets:		
Cash and cash equivalents	$ 206,505	$ 44,853
Accounts receivable, net of allowance for doubtful accounts of $23,679 and $18,013 at December 31, 2009 and 2008, respectively	337,151	360,357
Income taxes receivable	12,674	
Prepaid expenses	20,209	18,041
Other current assets	287,024	208,739
Total current assets	863,563	631,990
Property, plant and equipment, net	1,058,976	1,114,941
Goodwill	482,480	477,860
Equity-method investments	60,677	122,308
Intangible and other long-term assets, net	50,969	143,046
Total assets	$ 2,516,665	$ 2,490,145
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 63,466	$ 87,207
Accrued expenses	133,602	152,536
Income taxes payable		20,861
Deferred income taxes	30,501	36,830
Current maturities of long-term debt	810	810
Total current liabilities	228,379	298,244
Deferred income taxes	209,053	246,824
Long-term debt, net	848,665	654,199
Other long-term liabilities	52,523	36,605
Stockholders equity:		
Preferred stock of $0.01 par value. Authorized, 5,000,000 shares; none issued		
	79	78

Common stock of $0.001 par value. Authorized, 125,000,000 shares; issued and outstanding 78,559,350 and 78,028,072 shares at December 31, 2009 and 2008, respectively		
Additional paid in capital	387,885	375,436
Accumulated other comprehensive loss, net	(18,996)	(32,641)
Retained earnings	809,077	911,400
Total stockholders equity	1,178,045	1,254,273
Total liabilities and stockholders equity	$ 2,516,665	$ 2,490,145

See accompanying notes to consolidated financial statements.

* As adjusted for ASC 470-20 (See note 8)

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Consolidated Statements of Operations
Years Ended December 31, 2009, 2008 and 2007
(in thousands, except per share data)

	2009	2008 *	2007 *
Oilfield service and rental revenues	$ 1,449,300	$ 1,826,052	$ 1,379,767
Oil and gas revenues		55,072	192,700
Total revenues	1,449,300	1,881,124	1,572,467
Cost of oilfield services and rentals	824,034	885,308	631,545
Cost of oil and gas sales		12,986	66,580
Total cost of services, rentals and sales (exclusive of items shown separately below)	824,034	898,294	698,125
Depreciation, depletion, amortization and accretion	207,114	175,500	187,841
General and administrative expenses	259,093	282,584	228,146
Reduction in value of assets	212,527		
Gain on sale of businesses	2,084	40,946	7,483
Income (loss) from operations	(51,384)	565,692	465,838
Other income (expense):			
Interest expense, net of amounts capitalized	(50,906)	(46,684)	(48,436)
Interest income	926	2,975	2,662
Other income (expense)	571	(3,977)	189
Earnings (losses) from equity-method investments, net	(22,600)	24,373	(2,940)
Reduction in value of equity-method investment	(36,486)		
Income (loss) before income taxes	(159,879)	542,379	417,313
Income taxes	(57,556)	190,904	145,755
Net income (loss)	$ (102,323)	$ 351,475	$ 271,558
Basic earnings (loss) per share	$ (1.31)	$ 4.39	$ 3.35

Diluted earnings (loss) per share	$ (1.31)	$ 4.33	$ 3.30
Weighted average common shares used in computing earnings per share:			
Basic	78,171	79,990	80,973
Incremental common shares from stock options		1,163	1,358
Incremental common shares from restricted stock units		60	58
Diluted	78,171	81,213	82,389

See accompanying notes to consolidated financial statements.

* As adjusted for ASC 470-20 (See note 8)

SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidated Statements of Changes in Stockholders Equity

Years Ended December 31, 2009, 2008 and 2007

(in thousands, except share data)

	Preferred stock shares	Preferred stock	Common stock shares	Common stock	Additional paid-in capital *	Accumulated other comprehensive income (loss), net	Retained earnings *	Total
Balances, December 31, 2006		$	80,617,337	$81	$ 466,501	$ 10,288	$288,367	$ 765,237
Comprehensive income:								
Net income							271,558	271,558
Other comprehensive income - Changes in fair value of hedging positions of equity-method investments, net of tax						(2,580)		(2,580)
Foreign currency translation adjustment						1,370		1,370
Total comprehensive income						(1,210)	271,558	270,348
Grant of restricted stock units					840			840
Restricted stock grant and compensation expense, net of forfeitures			160,234		2,685			2,685
Exercise of stock options			867,916	1	8,439			8,440
Tax benefit from exercise of stock options					9,408			9,408
Stock option compensation					1,529			1,529

expense						
Shares issued under Employee Stock Purchase Plan	26,163		949			949
Shares repurchased and retired	(1,000,000)	(1)	(33,769)			(33,770)
Balances, December 31, 2007	$ 80,671,650	$81	$ 456,582	$ 9,078	$559,925	$1,025,666
Comprehensive income:						
Net income					351,475	351,475
Other comprehensive income - Changes in fair value of hedging positions of equity-method investments, net of tax				6,460		6,460
Foreign currency translation adjustment				(48,179)		(48,179)
Total comprehensive income				(41,719)	351,475	309,756
Grant of restricted stock units			840			840
Restricted stock grant and compensation expense, net of forfeitures	501,112	1	4,685			4,686
Exercise of stock options	426,592		4,274			4,274
Tax benefit from exercise of stock options			5,411			5,411
Stock option compensation expense			2,643			2,643
Shares issued to settle restricted	14,559					

stock units						
Shares issued to pay performance share units	74,405		2,948			2,948
Shares issued under Employee Stock Purchase Plan	56,754		1,833			1,833
Shares repurchased and retired	(3,717,000)	(4)	(103,780)			(103,784)
Balances, December 31, 2008	$ 78,028,072	$78	$ 375,436	$ (32,641)	$911,400	$1,254,273

See accompanying notes to consolidated financial statements.

* As adjusted for ASC 470-20 (See note 8)

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Consolidated Statements of Changes in Stockholders Equity (Continued)
Years Ended December 31, 2009, 2008 and 2007
(in thousands, except share data)

	Preferred stock shares	Preferred stock	Common stock shares	Common stock	Additional paid-in capital	Accumulated other comprehensive income (loss), net	Retained earnings	Total
Balances, December 31, 2008		$	78,028,072	$78	$375,436	$(32,641)	$ 911,400	$1,254,273
Comprehensive income:								
Net income (loss)							(102,323)	(102,323)
Other comprehensive income - Disposition of hedging positions of equity-method investments, net of tax						(3,881)		(3,881)
Foreign currency translation adjustment						17,526		17,526
Total comprehensive loss						13,645	(102,323)	(88,678)
Grant of restricted stock units					700			700
Restricted stock grant and compensation expense, net of forfeitures			305,182	1	5,837			5,838
Exercise of stock options			38,717		375			375
Tax benefit from exercise of stock options					170			170
Stock option compensation expense					2,401			2,401
Shares issued to pay performance share units			71,392		920			920
Shares issued under Employee Stock Purchase Plan			133,360		2,308			2,308
Shares withheld and retired			(17,373)		(262)			(262)
Balances, December 31, 2009		$	78,559,350	$79	$387,885	$(18,996)	$ 809,077	$1,178,045

See accompanying notes to consolidated financial statements.

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Consolidated Statements of Cash Flows
Years Ended December 31, 2009, 2008 and 2007
(in thousands)

	2009	2008 *	2007 *
Cash flows from operating activities:			
Net income (loss)	$ (102,323)	$ 351,475	$ 271,558
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	207,114	175,500	187,841
Deferred income taxes	(74,704)	103,504	65,565
Reduction in value of assets	212,527		
Reduction in value of equity-method investments	36,486		
Tax benefit from exercise of stock options	(170)	(5,411)	(9,408)
Stock based and performance share unit compensation expense, net	11,785	12,182	12,549
Retirement and deferred compensation plans (income) expense, net	1,550	15,255	(189)
(Earnings) losses from equity-method investments, net of cash received	28,606	(7,102)	2,940
Amortization of debt acquisition costs and note discount	21,744	19,963	18,697
Gain on sale of businesses	(2,084)	(40,946)	(7,483)
Changes in operating assets and liabilities, net of acquisitions and dispositions:			
Receivables	25,609	(77,565)	(25,361)
Other current assets	(51,320)	(184,602)	4,652
Accounts payable	(24,637)	20,252	(7,036)
Accrued expenses	(41,264)	(5,917)	7,591
Decommissioning liabilities		(6,160)	(2,769)
Income taxes	(2,301)	12,434	8,524
Other, net	29,485	19,497	2,612
Net cash provided by operating activities	276,103	402,359	530,283
Cash flows from investing activities:			
Payments for capital expenditures	(286,277)	(453,861)	(410,518)
Acquisitions of businesses, net of cash acquired	(1,247)	(8,410)	(110,973)
Acquisitions of oil and gas properties, net of cash acquired			(8,000)
Cash proceeds from sale of businesses, net of cash sold	7,716	155,312	18,100
Cash contributed to equity-method investment	(8,694)		
Other	(3,769)	(3,578)	9,280
Net cash used in investing activities	(292,271)	(310,537)	(502,111)
Cash flows from financing activities:			
Net borrowings from revolving line of credit	177,000		

Principal payments on long-term debt	(810)	(810)	(810)
Payment of debt acquisition costs	(2,308)		(83)
Proceeds from exercise of stock options	375	4,274	8,440
Tax benefit from exercise of stock options	170	5,411	9,408
Proceeds from issuance of stock through employee benefit plans	1,958	1,558	806
Purchase and retirement of stock		(103,784)	(33,770)
Net cash provided by (used in) financing activities	176,385	(93,351)	(16,009)
Effect of exchange rate changes on cash	1,435	(5,267)	516
Net increase (decrease) in cash and cash equivalents	161,652	(6,796)	12,679
Cash and cash equivalents at beginning of year	44,853	51,649	38,970
Cash and cash equivalents at end of year	$ 206,505	$ 44,853	$ 51,649

See accompanying notes to consolidated financial statements.

* As adjusted for ASC 470-20 (See note 8)

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements
December 31, 2009, 2008 and 2007

(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 2009 presentation.

(b) Business

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

(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 significant 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

The majority of the Company s business is conducted with major and independent oil and gas exploration companies. The Company evaluates the financial strength of its customers and provides allowances for probable credit losses when deemed necessary.

The market for the Company s services and products is the offshore and onshore oil and gas industry in the United States and select international market areas. Oil and gas companies make capital expenditures on exploration, drilling and production operations. The level of these expenditures historically has been characterized by significant volatility.

The Company derives a large amount of revenue from a small number of major and independent oil and gas companies. In 2009 and 2008, Chevron accounted for approximately 15% and 12%, respectively, Apache accounted for approximately 13% and 11%, respectively and BP accounted for approximately 11% of total revenue primarily related to our subsea and well enhancement segment. In 2007, Shell accounted for approximately 11% of total revenue, primarily related to our oil and gas and drilling products and services segments.

(e) Cash Equivalents

The Company considers all short-term investments with a maturity of 90 days or less when purchased to be cash equivalents.

(f) Accounts Receivable and Allowances

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

(g) Other Current Assets

Other current assets include approximately $210.0 million and $168.3 million of costs incurred and estimated earnings in excess of billings on uncompleted contracts at December 31, 2009 and 2008, respectively. The Company follows the percentage-of-completion method of accounting for applicable contracts. Accordingly, income is recognized in the ratio that costs incurred bears to estimated total costs. Adjustments to cost estimates are made periodically, and losses expected to be incurred on contracts in progress are charged to operations in the period such losses are determined.

Additionally, other current assets include approximately $38.4 million and $31.5 million of raw materials and supplies at December 31, 2009 and 2008, respectively. Raw materials and supplies consist principally of products which are consumed in our services provided to customers, spare parts and supplies for equipment used in providing these services, and raw materials used for finished products. These supplies are stated at the lower of cost or market. Cost primarily represents invoiced costs. Cost is determined on an average cost basis for all other raw materials and supplies.

(h) Property, Plant and Equipment

Property, plant and equipment are stated at cost, except for assets acquired using purchase accounting, which are recorded at fair value as of the date of acquisition. With the exception of the Company s liftboats and derrick barges, depreciation is computed using the straight line method over the estimated useful lives of the related assets as follows:

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

The Company s liftboats and derrick barges are depreciated using the units-of-production method based on the utilization of the vessels and are subject to a minimum amount of annual depreciation. The units-of-production method is used for these assets because depreciation and depletion occur primarily through use rather than through the passage of time.

The Company capitalizes interest on 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. The Company capitalized approximately $2.9 million, $3.1 million and $1.5 million in 2009, 2008 and 2007, respectively, of interest for various capital projects.

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 assessed by a comparison of the carrying amount of assets to their fair value calculated, in part, by the 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 leg length. These groupings represent the lowest level of identifiable cash flows. The Company has long-lived assets, such as facilities, utilized by multiple operating divisions that do not have identifiable cash flows. Impairment testing for these long-lived assets is based on the consolidated entity. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. For the year ended December 31, 2009, we recorded approximately $119.8 million reduction in the value of property, plant and equipment due to the decline in the North American land markets (see note 3).

(i) Goodwill

The Company accounts for goodwill and other intangible assets in accordance with Accounting Standards Codification 350-10 (ASC 350-10), Intangibles Goodwill and Other. ASC 350-10 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 at December 31, 2009, the Company identified its reporting units (which are consistent with the Company s operating segments) and determined 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 estimated the fair value of each reporting unit and compared it to the reporting unit s carrying value. Based on this test, the fair values of the reporting units substantially exceeded the carrying amounts. No impairment loss was recognized in the years ended December 31, 2009, 2008 or 2007 under this method. The following table summarizes the activity for the Company s goodwill for the years ended December 31, 2009 and 2008 (amounts in thousands):

	Subsea and Well Enhancement	Drilling Products and Services	Marine	Total
Balance, December 31, 2007	$329,692	$143,740	$11,162	$484,594
Acquisition activities	2,241	1,499		3,740
Additional consideration paid for prior acquisitions	387	1,075		1,462
Foreign currency translation adjustment	(242)	(11,694)		(11,936)
Balance, December 31, 2008	$332,078	$134,620	$11,162	$477,860
Disposition activities			(229)	(229)
Additional consideration paid or accrued for prior acquisitions		1,731		1,731
Foreign currency translation adjustment	33	3,085		3,118
Balance, December 31, 2009	$332,111	$139,436	$10,933	$482,480

If, among other factors, (1) the Company s market capitalization declines and remains below its stockholders equity, (2) the fair value of the reporting units decline, or (3) the adverse impacts of economic or competitive factors are worse than anticipated, the Company could conclude in future periods that impairment losses are required in order to reduce the carrying value of its goodwill and long-lived assets.

(j) Intangible and Other Long-Term Assets

Intangible and other long-term assets consist of the following at December 31, 2009 and 2008 (amounts in thousands):

	December 31, 2009			December 31, 2008		
	Gross Amount	Accumulated Amortization	Net Balance	Gross Amount	Accumulated Amortization	Net Balance
Customer relationships	$ 12,826	$ (2,777)	$ 10,049	$ 108,811	$ (14,424)	$ 94,387
Tradenames	2,654	(808)	1,846	15,812	(1,813)	13,999
Non-compete agreements	1,465	(1,117)	348	1,705	(1,071)	634
Debt acquisition costs	20,704	(10,237)	10,467	17,492	(5,865)	11,627
Deferred compensation plan assets	12,382		12,382	7,212		7,212
Long-term assets held as major replacement spares	13,774		13,774	14,859		14,859
Other	2,412	(309)	2,103	586	(258)	328
Total	$ 66,217	$ (15,248)	$ 50,969	$ 166,477	$ (23,431)	$ 143,046

Customer relationships, tradenames, and non-compete agreements are amortized using the straight line method over the life of the related asset with weighted average useful lives of 11 years, 9 years, and 3 years, respectively. Debt acquisition costs are amortized primarily using the effective interest method over the life of the related debt agreements with a weighted average useful life of 7 years. Amortization of debt acquisition costs is recorded in interest expense. Amortization expense (exclusive of debt acquisition costs) was approximately $4.3 million, $9.1 million and $7.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. Estimated annual amortization of intangible assets (exclusive of debt acquisition costs) will be approximately $1.7 million for 2010, $1.5 million for 2011 and 2012, and $1.4 million for 2013 and 2014, excluding the effects of any acquisitions or dispositions subsequent to December 31, 2009.

In connection with the review for impairment of long-lived assets in accordance with Accounting Standards Codification 360-10 (ASC 360-10), Property, Plant and Equipment, the Company recorded approximately $92.7 million as a reduction in the value of intangible assets during the year ended December 31, 2009 (see note 3).

(k) Decommissioning Liability

Prior to the sale of 75% of its interest in SPN Resources, the Company recorded estimated future decommissioning liabilities related to its oil and gas producing properties pursuant to the provisions of Accounting Standards Codification 410-20 (ASC 410-20), Asset Retirement Obligations. ASC 410-20 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 was required to be accreted each period to present value.

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The following table summarizes the activity for the Company s decommissioning liability for the year ended December 31, 2008 (amounts in thousands):

Decommissioning liabilities, beginning of period	$ 124,970
Liabilities acquired and incurred	
Liabilities disposed or settled	(104,362)
Accretion	1,019
Revision in estimated liabilities	(21,627)
Decommissioning liabilities, end of period	$

(l) Revenue Recognition

Revenue is recognized when services or equipment are provided. The Company contracts for marine, subsea and well enhancement projects either on a day rate or turnkey basis, with a vast majority of its projects conducted on a day rate basis. The Company s drilling products and services 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 drilling products and services that are damaged or lost down-hole are reflected as revenue at the time of the incident. The Company is accounting for the revenue and related costs on a large-scale platform decommissioning contract on the percentage-of-completion method utilizing costs incurred as a percentage of total estimated costs (see note 5). Prior to the sale of 75% of its interest in SPN Resources, the Company recognized oil and gas revenue from its interests in producing wells as oil and natural gas was sold from those wells.

(m) Taxes Collected from Customers

Pursuant to Accounting Standards Codification 605-45-50-3, Taxes Collected from Customers and Remitted to Governmental Authorities, the Company elected to net taxes collected from customers against those remitted to government authorities in the financial statements consistent with the historical presentation of this information.

(n) Income Taxes

The Company accounts for income taxes and the related accounts under the asset and liability method. 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 (loss) per Share

Basic earnings (loss) per share is computed by dividing income (loss) 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.

Stock options and unvested restricted stock of approximately 640,000 shares were excluded in the computation of diluted earnings per share for the year ended December 31, 2009, as the effect would have been anti-dilutive due to the loss recorded for the year ended December 31, 2009.

In connection with the Company s outstanding senior exchangeable notes, there could be a dilutive effect on earnings per share if the price of the Company s common stock exceeds the initial exchange price of $45.58 per share for a specified period of time. In the event the Company s common stock exceeds $45.58 per share for a specified period of time, the first $1.00 the price exceeds $45.58 would cause a dilutive effect of approximately 188,400 shares. As the share price continues to increase, dilution would continue to occur but at a declining rate. The impact on the calculation of earnings per share varies depending on when during the quarter the $45.58 per share price is reached (see note 8).

(p) Financial Instruments

The fair value of the Company s financial instruments of cash equivalents, accounts receivable, equity-method investments and current maturities of long-term debt approximates their carrying amounts. The fair value of the Company s long-term debt was approximately $853.2 million and $515.5 million at December 31, 2009 and 2008, respectively. The fair value of these debt instruments is determined by reference to the market value of the instrument as quoted in an over-the-counter market.

(q) Foreign Currency

Results of operations for foreign subsidiaries with functional currencies other than the U.S. dollar are translated using average exchange rates during the period. Assets and liabilities of these foreign subsidiaries are translated using the exchange rates in effect at the balance sheet dates, and the resulting translation adjustments are reported as accumulated other comprehensive income (loss) in the Company s stockholders equity.

For non-U.S. subsidiaries where the functional currency is the U.S. dollar, financial statements are remeasured into U.S. dollars using the historical exchange rate for most of the long-term assets and liabilities and the balance sheet dates exchange rate for most of the current assets and liabilities. An average exchange rate is used for each period for revenues and expenses. These transaction gains and losses, as well as any other transactions in a currency other than the functional currency, are included in general and administrative expenses in the consolidated statements of operations in the period in which the currency exchange rates change. The Company recorded approximately $3.5 million and $4.3 million of foreign currency gains in the years ended December 31, 2009 and 2008, respectively. For the year ended December 31, 2007, the Company recorded approximately $0.5 million of such transaction losses.

(r) Stock-Based Compensation

In accordance with Accounting Standards Codification 718-10 (ASC 718-10), Compensation Stock Compensation, the Company records compensation costs relating to share based payment transactions within the general and administrative expenses in the financial statements. The cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee s requisite service period (generally the vesting period of the equity award).

(s) Hedging Activities

During 2008, the Company entered into forward foreign exchange contracts to hedge the impact of foreign currency fluctuations. The forward foreign exchange contracts generally have maturities ranging from one to eighteen months. The Company does not enter into forward foreign exchange contracts for trading purposes. At December 31, 2008, the Company had foreign currency forward contracts outstanding in order to hedge exposure to currency fluctuations between the British Pound Sterling and the Euro. These contracts are not designated as hedges, for hedge accounting treatment, and are marked to fair market value each period. Based on the exchange rates as of December 31, 2008, the Company recorded an immaterial gain to adjust these forward contracts to their fair market value. As of December 31, 2009, we had no outstanding foreign currency forward contracts.

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(t) Other Comprehensive Income (Loss)

The following table reconciles the change in accumulated other comprehensive income (loss) for the years ended December 31, 2009 and 2008 (amounts in thousands):

	Year Ended December 31, 2009	2008
Accumulated other comprehensive income (loss), net, December 31, 2008 and 2007, respectively	$ (32,641)	$ 9,078
Other comprehensive income (loss), net of tax:		
Hedging activities:		
Unrealized gain (loss) on hedging activities for equity-method investments, net of tax of ($2,279) in 2009 and $3,794 in 2008	(3,881)	6,460
Foreign currency translation adjustment	17,526	(48,179)
Total other comprehensive income (loss)	13,645	(41,719)
Accumulated other comprehensive loss, net, December 31, 2009 and 2008, respectively	$ (18,996)	$ (32,641)

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(2) Supplemental Cash Flow Information

The following table includes the Company s supplemental cash flow information for the years ended December 31, 2009, 2008 and 2007 (amounts in thousands):

	2009	2008	2007
Cash paid for interest (net of amount capitalized)	$ 28,833	$ 29,621	$ 32,049
Cash paid for income taxes	$ 9,786	$ 70,481	$ 69,233
Details of business acquisitions:			
Fair value of assets	$ 1,247	$ 8,589	$ 148,658
Fair value of liabilities		(179)	(32,757)
Note payable due on acquisition			(300)
Cash paid	1,247	8,410	115,601
Less cash acquired			(4,628)
Net cash paid for acquisitions	$ 1,247	$ 8,410	$ 110,973
Details of oil and gas property acquisitions:			
Fair value of assets received	$	$	$ 12,806
Fair value of assets disposed			(4,806)
Fair value of liabilities			
Cash paid			8,000
Less cash acquired			
Net cash paid for acquisitions	$	$	$ 8,000
Details of proceeds from sale of businesses:			
Book value of assets	$ 5,632	$ 297,321	$ 12,617
Book value of liabilities		(118,894)	
Note receivable due from sale			(2,000)
Investment retained		(48,571)	
Liability retained		2,900	
Gain on sale of business	2,084	40,946	7,483
Cash received	7,716	173,702	18,100
Less cash sold		(18,390)	
Net cash proceeds from sale of businesses	$ 7,716	$ 155,312	$ 18,100
Non-cash investing activity:			
Long term payable on vessel construction	$ 5,000	$	$

Additional consideration payable on acquisitions	$	484	$		$	

(3) Reduction in Value of Assets

In accordance with Accounting Standards Codification 360-10 (ASC 360-10), Property, Plant and Equipment, long-lived assets, such as property, plant and equipment and purchased intangibles subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Recoverability of assets to be held and used is assessed by a comparison of the carrying amount of such assets to their fair value calculated, in part, by the estimated undiscounted future cash flows expected to be generated by the assets. Cash flow estimates are based upon, among other things, historical results adjusted to reflect the best estimate of future market rates, utilization levels, and operating performance. 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. The Company s assets are grouped by subsidiary or division for the impairment testing, except for liftboats, which are grouped together by leg length. These groupings represent the lowest level of identifiable cash flows. If the assets fair value is less than the carrying amount of those items, impairment losses are recorded in the amount by which the carrying amount of such assets exceeds the fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less estimated costs to sell. The net carrying value of assets not fully recoverable is reduced to fair value. The estimate of fair value represents the Company s best estimate based on industry trends and reference to market transactions and is subject to variability. The oil and gas industry is cyclical and these estimates of the period over which future cash flows will be generated, as well as the predictability of these cash flows, can have a significant impact on the carrying values of these assets and, in periods of prolonged down cycles, may result in impairment charges. During the second quarter of 2009, the Company recorded approximately $92.7 million of expense in connection with intangible assets within the subsea and well enhancement segment. This reduction in value of intangible assets is primarily due to the decline in demand for services in the domestic land markets. During the fourth quarter of 2009, the domestic land markets remained depressed and the forecast of this market did not suggest a timely recovery sufficient to support the carrying values of these assets. As such, the Company recorded approximately $119.8 million of expense related to tangible assets (property, plant and equipment) within the same segment.

In accordance with Accounting Standards Codification 350-10, Intangibles Goodwill and Other, goodwill and other intangible assets with indefinite lives will not be amortized, but instead tested for impairment annually as of December 31 or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. In order to estimate the fair value of the reporting units (which is consistent with the reported business segments), the Company used a weighting of the discounted cash flow method and the public company guideline method of determining fair value of each reporting unit. The Company weighted the discounted cash flow method 80% and the public company guideline method 20% due to differences between the Company s reporting units and the peer companies size, profitability and diversity of operations. In order to validate the reasonableness of the estimated fair values obtained for the reporting units, a reconciliation of fair value to market capitalization was performed for each unit on a stand alone basis. A control premium, derived from market transaction data, was used in this reconciliation to ensure that fair values were reasonably stated in conjunction with the Company s capitalization. These fair value estimates were then compared to the carrying value of the reporting units. As the fair value of the reporting unit exceeded the carrying amount, no impairment loss was recognized during the year ended December 31, 2009. A significant amount of judgment was involved in performing these evaluations since the results are based on estimated future events.

(4) Acquisitions and Dispositions

In November 2009, the Company sold four 145-foot leg length liftboats for approximately $7.7 million. As a result of this sale, the Company recorded a pre-tax gain of approximately $2.1 million for the year ended December 31, 2009.

On March 14, 2008, the Company completed the sale of 75% of its interest in SPN Resources, LLC (SPN Resources). As part of this transaction, SPN Resources contributed an undivided 25% of its working interest in each of its oil and gas properties to a newly formed subsidiary and then sold all of its equity interest in the subsidiary. SPN Resources then effectively sold 66 2/3% of its outstanding membership interests. These two transactions generated cash proceeds to the Company of approximately $167.2 million and resulted in a pre-tax gain of approximately $37.1 million. SPN Resources operations constituted substantially all of the Company s oil and gas segment. The Company retained preferential rights on certain service work, entered into a turnkey contract to perform well abandonment and decommissioning work and guaranteed SPN Resources performance of its decommissioning liabilities. Subsequent to March 14, 2008, the Company accounts for its remaining 33 1/3% interest in SPN Resources using the equity-method of accounting. The results of SPN Resources operations through March 14, 2008 were consolidated (see notes 5 and 15).

In connection with the 2007 sale of a non-core drilling products and services business, the Company received cash of approximately $6.0 million, which resulted in an additional pre-tax gain on the sale of the business of approximately $3.3 million for the year ended December 31, 2008.

The Company also sold the assets of its field management division in 2007. In conjunction with the sale of this division, the Company received cash of $0.5 million during the year ended December 31, 2008, all of which resulted in an additional pre-tax gain on the sale of the business.

The Company made other business acquisitions, which were not material on an individual or cumulative basis, for cash consideration of $7.0 million for the year ended December 31, 2008.

On January 1, 2009, the Company adopted Accounting Standards Codification 805-10 (ASC 805-10), Business Combinations. ASC 805-10 requires an acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction and any noncontrolling interest in the acquiree at the acquisition date fair value. Additionally, contingent consideration and contractual contingencies shall be measured at acquisition date fair value. ASC 805-10 applies prospectively to business combinations after January 1, 2009. Several of the Company s prior business acquisitions require future payments if specific conditions are met. As of December 31, 2009, the maximum additional contingent consideration payable was approximately $26.3 million and will be determined and payable through 2012. Since these acquisitions occurred before the adoption of ASC 805-10, these amounts are not classified as liabilities and are not reflected in the Company s financial statements until the amounts are fixed and determinable. The Company capitalized and paid additional consideration of approximately $1.4 million for the year ended December 31, 2008 as a result of prior acquisitions.

Subsequent Events

On January 26, 2010, the Company acquired 100% of the equity interest of Hallin Marine Subsea International Plc (Hallin), for approximately $162.3 million of cash. Additionally, the Company repaid approximately $55.2 million of Hallin s debt. Hallin is an international provider of integrated subsea services and engineering solutions, focused on installing, maintaining and extending the life of subsea wells. Hallin operates in international offshore oil and gas markets with offices and facilities located in Singapore; Jakarta, Indonesia; Perth, Australia; Aberdeen, Scotland; and Houston, Texas. The acquisition of Hallin provides the Company the opportunity to enhance its position in the subsea and well enhancement market through its existing subsea assets (remotely operated vehicles, saturation diving systems and chartered vessels) and newbuild vessel program. During the year ended December 31, 2009, the Company expensed approximately $4.9 million in acquisition related costs, which was recorded as general and administrative expenses in the consolidated statements of operations. As the initial valuation and subsequent accounting for this acquisition is incomplete due to the timing of the acquisition, the Company is unable to provide the acquisition date fair value measurement for each major class of assets acquired and liabilities assumed.

On January 31, 2010, the Company acquired 100% ownership of Shell s Gulf of Mexico Bullwinkle platform and related assets, and assumed the decommissioning obligation for such assets. Immediately after the Company acquired these assets, it sold an undivided 49% interest in them to Dynamic Offshore Resources, LLC, which will operate the assets. The Company will plug and abandon the 29 wells associated with Bullwinkle, which is the deepest fixed-leg production platform on the Outer Continental Shelf. The Bullwinkle platform will be decommissioned at the end of its economic life. As the initial valuation and subsequent accounting for this acquisition is incomplete due to the timing of the acquisition, the Company is unable to provide the acquisition date fair value measurement for each major class of assets acquired and liabilities assumed.

(5) Long-Term Contracts

In December 2007, the Company s wholly-owned subsidiary, Wild Well Control, Inc. (Wild Well), entered into contractual arrangements pursuant to which it is decommissioning seven downed oil and gas platforms and related wells located offshore in the Gulf of Mexico for a fixed sum of $750 million, which is payable in installments upon the completion of specified portions of work. The contract contains certain covenants primarily related to Wild Well s performance of the work. The work is currently expected to be completed in the first half of 2010. During the fourth quarter of 2009 as this project neared completion, the Company determined it was necessary to increase the total cost estimate due to various well conditions and other technical issues associated with this complex and challenging project. As such, the Company increased the total cost estimate approximately 11% which negatively impacted net income by approximately $44 million. The revenue related to the contract for decommissioning these downed platforms and wells is recorded on the percentage-of-completion method utilizing costs incurred as a percentage of total estimated costs. The cumulative effect of changes to estimated contract profits are recognized in the period in which the revisions are identified. Included in other current assets at December 31, 2009 and 2008 is approximately $209.5 million and $164.3 million, respectively, of costs and estimated earnings in excess of billings related to this contract.

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In connection with the sale of 75% of its interest in SPN Resources, the Company retained preferential rights on certain service work and entered into a turnkey contract to perform well abandonment and decommissioning work associated with oil and gas properties owned and operated by SPN Resources. This contract covers only routine end of life well abandonment and pipeline and platform decommissioning for properties owned and operated by SPN Resources at the date of closing and has a remaining fixed price of approximately $141.1 million and $147.4 million as of December 31, 2009 and 2008, respectively. The turnkey contract consists of numerous, separate billable jobs estimated to be performed through 2022. Each job is short-term in duration and will be individually recorded on the percentage-of-completion method utilizing costs incurred as a percentage of total estimated costs.

(6) Property, Plant and Equipment

A summary of property, plant and equipment at December 31, 2009 and 2008 (in thousands) is as follows:

	2009	2008
Buildings, improvements and leasehold improvements	$ 105,650	$ 83,820
Marine vessels and equipment	333,350	289,438
Machinery and equipment	1,095,402	1,113,130
Automobiles, trucks, tractors and trailers	26,499	48,820
Furniture and fixtures	28,050	25,475
Construction-in-progress	49,483	93,864
Land	12,021	10,934
	1,650,455	1,665,481
Accumulated depreciation	(591,479)	(550,540)
Property, plant and equipment, net	$ 1,058,976	$ 1,114,941

In connection with the review for impairment of long-lived assets in accordance with ASC 360-10, the Company recorded approximately $119.8 million as a reduction in the value of property, plant and equipment during the year ended December 31, 2009 (see note 3).

The Company had approximately $22 million and $15 million of leasehold improvements at December 31, 2009 and 2008, respectively. These leasehold improvements are depreciated over the shorter of the life of the asset or the life of the lease using the straight line method. Depreciation expense (excluding depletion, amortization and accretion) was approximately $202.8 million, $163.6 million and $121.3 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(7) Equity-Method Investments

Investments in entities that are not controlled by the Company, but where the Company has the ability to exercise influence over the operations, are accounted for using the equity-method. The Company s share of the income or losses of these entities is reflected as earnings or losses from equity-method investments in its Condensed Consolidated Statements of Operations.

On March 14, 2008, the Company sold 75% of its original interest in SPN Resources (see note 4). The Company s equity-method investment balance in SPN Resources was approximately $52.3 million at December 31, 2009 and $65.2 million at December 31, 2008. The Company recorded losses from its equity-method investment in SPN Resources of approximately $7.6 million for the year ended December 31, 2009. From the date of sale through December 31, 2008, the Company recorded earnings from its equity-method investment in SPN Resources of approximately $34.3 million. Additionally, the Company received $5.9 million and $17.0 million of cash distributions from its equity-method investment in SPN Resources for the years ended December 31, 2009 and 2008, respectively.

The Company, where possible and at competitive rates, provides its products and services to assist SPN Resources in producing and developing its oil and gas properties. The Company had a receivable from this equity-method investment of approximately $1.9 million and $2.4 million at December 31, 2009 and 2008, respectively. The Company also recorded revenue from this equity-method investment of approximately $11.0

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million for the year ended December 31, 2009 and $15.2 million from the date of sale through December 31, 2008. The Company also reduces its revenue and its investment in SPN Resources for its respective ownership interest when products and services are provided to and capitalized by SPN Resources. As these capitalized costs are depleted by SPN Resources, the Company then increases its revenue and investment in SPN Resources. As such, the Company recorded a net increase in revenue and its investment in SPN Resources of approximately $0.6 million for the year ended December 31, 2009. The Company recorded a net decrease in revenue and its investment in SPN Resources of approximately $0.7 million from the date of sale through December 31, 2008.

During the year ended December 31, 2009, the Company wrote off the remaining carrying value of its 40% interest in Beryl Oil and Gas L.P. (BOG), $36.5 million, and suspended recording its share of BOG s operating results under equity-method accounting as a result of continued negative BOG operating results, lack of viable interested buyers and unsuccessful attempts to renegotiate the terms and conditions of its loan agreements with lenders on terms that would preserve the Company s investment. The Company s total cash contribution for this equity-method investment in BOG was approximately $57.8 million. The Company s equity-method investment balance in BOG was approximately $56.4 million at December 31, 2008. The Company recorded losses from its equity-method investment in BOG of approximately $14.0 million, $9.9 million and $3.0 million for the years ended December 31, 2009, 2008 and 2007, respectively. The Company had a receivable from this equity-method investment of approximately $1.0 million at December 31, 2008. The Company offset its general and administrative expenses by approximately $4.1 million for the reimbursements due from BOG for the year ended December 31, 2007. The Company also recorded revenue of approximately $7.0 million, $2.1 million and $8.0 million from BOG for the years ended December 31, 2009, 2008 and 2007, respectively. The Company also recorded a net increase (decrease) in its investment in BOG of ($6.1) million, $10.2 million and ($4.1) million for the years ended December 31, 2009, 2008 and 2007, respectively, for its proportionate share of accumulated other comprehensive income generated from hedging transactions. The Company recorded a net increase (reduction) in revenue and its investment in BOG for services provided by the Company that were capitalized by BOG of approximately $0.2 million, $0.1 million and ($0.6) million for the years ended December 31, 2009, 2008 and 2007.

In October 2009, DBH, LLC (DBH) acquired BOG in connection with a restructuring of BOG in which the previously existing debt obligations of BOG were partially extinguished and otherwise renegotiated. Simultaneous with that acquisition, the Company acquired a 24.6% membership interest in DBH for approximately $8.7 million. The Company s equity-method investment balance in DBH was approximately $7.7 million at December 31, 2009. From the date of acquisition through December 31, 2009, the Company recorded a loss from its equity-method investment in DBH of approximately $1.0 million. The Company had a receivable from this equity-method investment of approximately $2.3 million at December 31, 2009. The Company also recorded revenue from this equity-method investment of approximately $2.4 million from the date of acquisition through December 31, 2009.

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Combined summarized financial information for all investments that are accounted for using the equity-method of accounting is as follows (in thousands):

	December 31, 2009	December 31, 2008
Current Assets	$ 162,870	$ 245,416
Noncurrent assets	500,187	645,324
Total assets	$ 663,057	$ 890,740
Current liabilities	$ 81,675	$ 407,718
Noncurrent liabilities	218,003	124,139
Total liabilities	$ 299,678	$ 531,857

	Years Ended December 31, 2009	2008	2007
Revenues	$ 245,092	$ 315,895	$ 224,205
Cost of sales	110,101	238,656	175,872
Gross profit	$ 134,991	$ 77,239	$ 48,333
Income (loss) from continuing operations	$ (10,024)	$ 58,680	$ 35,163

(8) Long-Term Debt

The Company s long-term debt as of December 31, 2009 and 2008 consisted of the following (in thousands):

	2009	2008
Senior Notes interest payable semiannually at 6.875%, due June 2014	$ 300,000	$ 300,000
Discount on 6.875% Senior Notes	(2,813)	(3,336)
Senior Exchangeable Notes interest payable semiannually at 1.5% until December 2011 and 1.25% thereafter, due December 2026	400,000	400,000
Discount on 1.5% Senior Exchangeable Notes	(38,878)	(56,631)
U.S. Government guaranteed long-term financing interest payable semiannually at 6.45%, due in semiannual installments through June 2027	14,166	14,976
Revolver interest payable monthly at floating rate, due in June 2011	177,000	
	849,475	655,009
Less current portion	810	810
Long-term debt	$ 848,665	$ 654,199

Effective January 1, 2009, the Company has retrospectively adopted Accounting Standards Codification 470-20 (ASC 470-20), Debt with Conversion and Other Options. ASC 470-20 requires the proceeds from the issuance of our 1.50% senior exchangeable notes (described below) to be allocated between a liability component (issued at a discount) and an equity component. The resulting debt discount is amortized over the period the exchangeable debt is expected to be outstanding as additional non-cash interest expense. The Company used an effective interest rate of 6.89% and will amortize this initial debt discount through December 12, 2011. The carrying amount of the equity component was $55.1 million. The principal amount of the liability component, its unamortized discount and its net carrying value as of December 31, 2009 and 2008 were as follows (in thousands):

As of	Principal Amount	Unamortized Discount	Net Carrying Value
December 31, 2008	$400,000	$56,631	$343,369
December 31, 2009	$400,000	$33,878	$366,122

The provisions of ASC 470-20 are effective for fiscal years beginning after December 15, 2008 and require retrospective application. The Company s comparative balance sheet as of December 31, 2008 has been adjusted as follows (in thousands):

	As Originally Reported	Effect of Change	As Adjusted
Intangible assets and other long-term assets, net	$144,534	$ (1,488)	$143,046
Deferred income taxes	$226,421	$ 20,403	$246,824
Long-term debt, net	$710,830	$(56,631)	$654,199
Additional paid in capital	$320,309	$ 55,127	$375,436
Retained earnings	$931,787	$(20,387)	$911,400

The condensed consolidated statements of operations were retrospectively modified from the previously reported amounts as follows (in thousands, except per share amounts):

	Year Ended December 31, 2008	2007
Additional pre-tax non-cash interest expense, net	$ (16,265)	$ (15,179)
Additional deferred tax benefit	6,018	5,617
Retrospective change in net income	$ (10,247)	$ (9,562)
Change to basic earnings per share	$ (0.13)	$ (0.12)
Change to diluted earnings per share	$ (0.13)	$ (0.12)

The non-cash increase to interest expense, exclusive of amounts to be capitalized, was approximately $17.8 million for the year ended December 31, 2009, and will be approximately $19.2 million and $19.7 million for the years ended December 31, 2010 and 2011, respectively.

In May 2009, the Company amended its revolving credit facility to increase its borrowing capacity to $325 million from $250 million. Any amounts outstanding under the revolving credit facility are due on June 14, 2011. Costs associated with amending the revolving credit facility were approximately $2.3 million. These costs were capitalized and are being amortized over the remaining term of the credit facility. At December 31, 2009, the Company had

$177.0 million outstanding under the revolving credit facility with a weighted average interest rate of 2.98% per annum. Prior to December 31, 2009 and in connection with our acquisition of Hallin in January 2010, the Company borrowed approximately $169.8 million against the revolving credit facility (see notes 4 and 20).

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The Company also had approximately $11.6 million of letters of credit outstanding, which reduce the Company s borrowing availability under this credit facility. Amounts borrowed under the credit facility bear 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 domestic subsidiaries. The credit facility contains customary events of default and requires that the Company satisfy various financial covenants. It also limits the Company s ability to pay dividends or make other distributions, make acquisitions, make changes to the Company s capital structure, create liens or incur additional indebtedness. At December 31, 2009, the Company was in compliance with all such covenants.

At December 31, 2009, the Company had outstanding $14.2 million 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, for two 245-foot class liftboats. The debt bears interest at 6.45% per annum and is payable in equal semi-annual installments of $405,000 on June 3rd and December 3rd of each year through the maturity date of 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, working capital and debt-to-equity requirements. At December 31, 2009, the Company was in compliance with all such covenants.

The Company also has outstanding $300 million of 6 7/8% unsecured senior notes due 2014. The indenture governing the senior notes requires semi-annual interest payments on June 1st and December 1st of each year through the maturity date of June 1, 2014. The indenture contains certain covenants that, among other things, limit the Company from incurring additional debt, repurchasing capital stock, paying dividends or making other distributions, incurring liens, selling assets or entering into certain mergers or acquisitions. At December 31, 2009, the Company was in compliance with all such covenants.

The Company has outstanding $400 million of 1.50% unsecured senior exchangeable notes due 2026. Effective January 1, 2009, the Company retrospectively adopted ASC 470-20 as it pertains to these exchangeable notes. The exchangeable notes bear interest at a rate of 1.50% per annum that decreases to 1.25% per annum on December 15, 2011. Interest on the exchangeable notes is payable semi-annually on December 15th and June 15th of each year through the maturity date of December 15, 2026. The exchangeable notes do not contain any restrictive financial covenants.

Under certain circumstances, holders may exchange the notes for shares of the Company s common stock. The initial exchange rate is 21.9414 shares of common stock per $1,000 principal amount of notes. This is equal to an initial exchange price of $45.58 per share. The exchange price represents a 35% premium over the closing share price at date of issuance. The notes may be exchanged under the following circumstances:

- during any fiscal quarter (and only during such fiscal quarter), if the last reported sale price of the Company s common stock is greater than or equal to 135% of the applicable exchange price of the notes for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter;

- prior to December 15, 2011, during the five business-day period after any ten consecutive trading-day period (the measurement period) in which the trading price of $1,000 principal amount of notes for each trading day in the measurement period was less than 95% of the product of the last reported sale price of the Company s common stock and the exchange rate on such trading day;

- if the notes have been called for redemption;

- upon the occurrence of specified corporate transactions; or

- at any time beginning on September 15, 2026, and ending at the close of business on the second business day immediately preceding the maturity date of December 15, 2026.

In connection with the exchangeable note transaction, the Company simultaneously entered into agreements with affiliates of the initial purchasers to purchase call options and sell warrants on its common stock. The Company may exercise the call options it purchased at any time to acquire approximately 8.8 million shares of its common stock at a strike price of $45.58 per share. The owners of the warrants may exercise the warrants to purchase from the Company approximately 8.8 million shares of the Company s common stock at a price of $59.42 per share, subject to certain anti-dilution and other customary adjustments. The warrants may be settled in cash, in common

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stock or in a combination of cash and common stock, at the Company s option. Lehman Brothers OTC Derivatives, Inc. (LBOTC) is the counterparty to 50% of the Company s call option and warrant transactions. In October 2008, LBOTC filed for bankruptcy protection. We continue to carefully monitor the developments affecting LBOTC. Although the Company may not be able to retain the benefit of the call option due to LBOTC s bankruptcy, the Company does not expect that there will be a material impact, if any, on the financial statements or results of operations. The call option and warrant transactions described above do not affect the terms of the outstanding exchangeable notes.

Annual maturities of long-term debt for each of the five fiscal years following December 31, 2009 and thereafter are as follows (in thousands):

2010	$ 810
2011	177,810
2012	810
2013	810
2014	300,810
Thereafter	410,116
Total	$ 891,166

(9) Stock Based and Long-Term Compensation

The Company maintains various stock incentive plans that provide long-term incentives to the Company s key employees, including officers, directors, consultants and advisers (Eligible Participants). Under the incentive plans, 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. The Compensation Committee of the Company s Board of Directors establishes the terms and conditions of any awards granted under the plans, provided that the exercise price of any stock options granted may not be less than the fair value of the common stock on the date of grant.

Stock Options

The Company has granted non-qualified stock options under its stock incentive plans. The options generally vest in equal installments over three years and expire in ten years. Non-vested options are generally forfeited upon termination of employment. In 2008, the Company amended its outstanding employee stock options to (1) provide immediate vesting of the stock options upon the optionee s termination of employment due to death and disability, and, if approved by the Committee, upon retirement and termination of employment by the Company without cause, (2) make the period during which stock options can be exercised following termination of employment due to death, disability and retirement consistent among all outstanding option agreements by providing that the optionee has until the end of the original term of the stock option to exercise, and (3) extend the time during which the stock option may be exercised following a termination by the Company without cause or a termination without cause within one year following a change of control to five years following the termination, but in no event later than ten years following the date of grant. During 2009, the Company granted 309,352 non-qualified stock options under these same terms.

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In accordance with ASC 718-10, the Company recognizes compensation expense for stock option grants based on the fair value at the date of grant using the Black-Scholes-Merton option pricing model. The Company has contracted a third party to assist in the valuation of option grants. The Company uses historical data, among other factors, to estimate the expected price volatility, the expected option life and the expected forfeiture rate. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant for the expected life of the option. The following table presents the fair value of stock option grants made during the years ended December 31, 2009, 2008 and 2007 and the related assumptions used to calculate the fair value:

	Years Ended December 31,		
	2009 Actual	2008 Actual	2007 Actual
Weighted average fair value of grants	$ 8.95	$ 6.40	$ 14.34
Black-Scholes-Merton Assumptions:			
Risk free interest rate	1.77%	2.54%	3.67%
Expected life (years)	4	4	5
Volatility	53.57%	55.05%	38.90%
Dividend yield			

The Company s compensation expense related to stock options for the years ended December 31, 2009, 2008 and 2007 was approximately $2.4 million, $2.6 million and $1.5 million, respectively, which is reflected in general and administrative expenses.

The following table summarizes stock option activity for the years ended December 31, 2009, 2008 and 2007:

	Number of Options	Weighted Average Option Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2006	3,970,886	$ 12.91		
Granted	157,035	$ 35.84		
Exercised	(867,916)	$ 9.72		
Forfeited	(2,333)	$ 9.20		
Outstanding at December 31, 2007	3,257,672	$ 14.87		
Granted	437,530	$ 13.86		
Exercised	(426,592)	$ 10.02		
Forfeited	(700)	$ 9.31		
Outstanding at December 31, 2008	3,267,910	$ 15.37		
Granted	309,352	$ 20.01		
Exercised	(38,717)	$ 9.71		

Forfeited		$					
Outstanding at December 31, 2009	3,538,545	$	15.84	5.7	$	33,565
Exercisable at December 31, 2009	2,895,388	$	15.27	5.0	$	29,090
Options expected to vest	643,157	$	18.39	9.3	$	4,475

The aggregate intrinsic value in the table above represents the total pre-tax intrinsic value (the difference between the Company s closing stock price on December 31, 2009 and the option price, multiplied by the number of in-the-money options) that would have been received by the option holders if all the options had been exercised on

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December 31, 2009. The Company expects all of its remaining non-vested options to vest as they are primarily held by its officers and senior managers.

The total intrinsic value of options exercised during the year ended December 31, 2009 (the difference between the stock price upon exercise and the option price) was approximately $0.4 million. The Company received approximately $0.4 million, $4.3 million and $8.4 million during the years ended December 31, 2009, 2008 and 2007, respectively, from employee stock option exercises. In accordance with ASC 718-10, the Company has reported the tax benefits of approximately $0.2 million, $5.4 million and $9.4 million from the exercise of stock options for the years ended December 31, 2009, 2008 and 2007, respectively, as financing cash flows.

A summary of information regarding stock options outstanding at December 31, 2009 is as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Shares	Weighted Average Remaining Contractual Life	Weighted Average Price	Shares	Weighted Average Price
$ 7.31 - $ 8.79	102,331	2.9 years	$ 8.60	102,331	$ 8.60
$ 9.31 - $ 9.90	358,780	1.9 years	$ 9.39	358,780	$ 9.39
$10.36 - $10.90	1,168,600	4.6 years	$10.66	1,168,600	$10.66
$12.45 - $12.86	437,681	8.8 years	$12.87	149,230	$12.86
$17.46 - $25.00	1,168,555	6.7 years	$19.55	872,300	$19.30
$34.40 - $35.84	294,185	7.5 years	$35.73	238,538	$35.74
$40.00 - $40.69	8,413	8.2 years	$40.69	5,609	$40.69

The following table summarizes non-vested stock option activity for the year ended December 31, 2009:

	Number of Options	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2008	638,212	$ 8.67
Granted	309,352	$ 8.95
Vested	(304,407)	$ 9.97
Forfeited		$
Non-vested at December 31, 2009	643,157	$ 8.19

As of December 31, 2009, there was approximately $5.1 million of unrecognized compensation expense related to non-vested stock options outstanding. The Company expects to recognize approximately $2.5 million, $1.7 million and $0.9 million of compensation expense during the years 2010, 2011 and 2012, respectively, for these non-vested stock options outstanding.

Restricted Stock

During the year ended December 31, 2009, the Company granted 319,681 shares of restricted stock to its employees. Shares of restricted stock generally vest in equal annual installments over three years. Non-vested shares are generally forfeited upon the termination of employment. Holders 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 any dividends or other distributions. Compensation expense associated with restricted stock is measured based on the grant date fair value of our common stock and is recognized on a straight line basis over the vesting period. The Company s compensation expense related to restricted stock outstanding for the years ended December 31, 2009,

2008 and 2007 was approximately $5.8 million, $4.7 million and $2.7 million, respectively, which is reflected in general and administrative expenses.
A summary of the status of restricted stock for the year ended December 31, 2009 is presented in the table below:

	Number of Shares		Weighted Average Grant Date Fair Value
Non-vested at December 31, 2008	784,300	$	21.15
Granted	319,681	$	20.15
Vested	(132,461)	$	(33.57)
Forfeited	(14,499)	$	(20.90)
Non-vested at December 31, 2009	957,021	$	19.10

As of December 31, 2009, there was approximately $12.2 million of unrecognized compensation expense related to non-vested restricted stock. The Company expects to recognize approximately $6.1 million, $4.1 million and $2.0 million during the years 2010, 2011 and 2012, respectively, for non-vested restricted stock.

Restricted Stock Units

Under the Amended and Restated 2004 Directors Restricted Stock Units Plan, each non-employee director is issued a number of Restricted Stock Units (RSUs) having an aggregate dollar value determined by the Company s Board of Directors. The exact number of units is determined by dividing the dollar value determined by the Company s Board of Directors by the fair market value of the Company s common stock on the day of the annual stockholders meeting or a pro rata amount if the appointment occurs subsequent to the annual stockholders meeting. An RSU represents the right to receive from the Company, within 30 days of the date the director ceases to serve on the Board, one share of the Company s common stock. As a result of this plan, 93,648 restricted stock units were outstanding at December 31, 2009. The Company s expense related to RSUs for the years ended December 31, 2009, 2008 and 2007 was approximately $0.6 million, $0.8 million and $1.0 million, respectively, which is reflected in general and administrative expenses.
A summary of the activity of restricted stock units for the year ended December 31, 2009 is presented in the table below:

	Number of Restricted Stock Units		Weighted Average Grant Date Fair Value
Outstanding at December 31, 2008	59,668	$	34.01
Granted	33,980	$	20.60
Exhanged for common stock		$	
Outstanding at December 31, 2009	93,648	$	29.14

Performance Share Units

The Company has issued performance share units (PSUs) to its employees as part of the Company s long-term incentive program. There is a three year performance period associated with each PSU grant. 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. The PSUs provide for settlement in cash or up to 50% in equivalent value in the Company s common stock, if the participant has met specified continued service requirements. At December 31, 2009, there were 293,583 PSUs outstanding (50,960, 71,891, 83,032 and 87,700 related to performance periods ending December 31, 2009, 2010, 2011 and 2012, respectively). The Company s compensation expense related to all outstanding PSUs for the years ended December 31, 2009, 2008 and 2007 was approximately $7.3 million, $6.7 million and $7.2 million, respectively, which is reflected in general and administrative expenses. The Company has recorded a current liability of approximately $6.4 million and $5.6 million at December 31, 2009 and 2008, respectively, for outstanding PSUs, which is reflected in accrued expenses. Additionally, the Company has recorded a long-term liability of approximately $7.8 million and $6.9 million at December 31, 2009 and 2008, respectively, for outstanding PSUs, which is reflected in other long-term liabilities. In 2009 and 2008, the Company paid approximately $4.7 million and $2.9 million in cash, respectively, and issued approximately 71,400 and 74,400 shares, respectively, of its common stock to its employees to settle PSUs for the performance periods ended December 31, 2008 and 2007.

Employee Stock Purchase Plan

The Company has employee stock purchase plans under which an aggregate of 1,250,000 shares of common stock were reserved for issuance. Under these stock purchase plans, eligible employees can purchase shares of the Company s common stock at a discount. The Company received $2.0 million, $1.6 million and $0.8 million related to shares issued under these plans for the years ended December 31, 2009, 2008 and 2007, respectively. For the years ended December 31, 2009, 2008 and 2007, the Company recorded compensation expense of approximately $350,000, $275,000 and $143,000, respectively, which is reflected in general and administrative expenses. Additionally, the Company issued approximately 133,400, 57,000 and 26,000 shares for the years ended December 31, 2009, 2008 and 2007, respectively, related to these stock purchase plans.

(10) Income Taxes

The components of income and loss from continuing operations before income taxes for the years ended December 31, 2009, 2008 and 2007 are as follows (in thousands):

	2009	2008	2007
Domestic	$ (191,543)	$ 488,666	$ 359,821
Foreign	31,664	53,713	57,492
	$ (159,879)	$ 542,379	$ 417,313

The components of income tax expense (benefit) for the years ended December 31, 2009, 2008 and 2007 are as follows (in thousands):

	2009	2008	2007
Current			
Federal	$ 1,555	$ 69,065	$ 67,211
State	(256)	3,699	2,917
Foreign	16,019	20,047	19,470
	17,318	92,811	89,598
Deferred			
Federal	(71,874)	96,770	54,544
State	(1,831)	1,805	1,170
Foreign	(1,169)	(482)	443
	(74,874)	98,093	56,157

	$ (57,556)	$ 190,904	$ 145,755

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Income tax expense differs from the amounts computed by applying the U.S. Federal income tax rate of 35% to income (loss) before income taxes for the years ended December 31, 2009, 2008 and 2007 as follows (in thousands):

	2009	2008	2007
Computed expected tax expense	$ (55,958)	$ 189,833	$ 146,060
Increase (decrease) resulting from			
State and foreign income taxes	(3,712)	1,865	2,059
Other	2,114	(794)	(2,364)
Income tax	$ (57,556)	$ 190,904	$ 145,755

The significant components of deferred income taxes at December 31, 2009 and 2008 are as follows (in thousands):

	2009	2008
Deferred tax assets:		
Allowance for doubtful accounts	$ 8,166	$ 3,893
Operating loss and tax credit carryforwards	41,154	9,533
Compensation and employee benefits	22,259	20,211
Deferred interest expense related to exchangeable notes	999	2,478
Other	16,457	20,464
	89,035	56,579
Valuation allowance	(2,394)	(2,394)
Net deferred tax assets	86,641	54,185
Deferred tax liabilities:		
Property, plant and equipment	216,411	220,347
Goodwill and other intangible assets	16,714	49,451
Deferred revenue on long-term contracts	77,530	60,811
Other	15,540	7,230
Deferred tax liabilities	326,195	337,839
Net deferred tax liability	$ 239,554	$ 283,654

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.

Net deferred tax liabilities were classified in the consolidated balance sheet at December 31, 2009 and 2008 as follows (in thousands):

	2009	2008

Deferred tax liabilities:		
Current deferred income taxes	$ 30,501	$ 36,830
Noncurrent deferred income taxes	209,053	246,824
Net deferred tax liability	$ 239,554	$ 283,654

As of December 31, 2009, the Company had approximately $94.8 million in net operating loss carryforwards, which are available to reduce future taxable income. The expiration dates for utilization of the loss carryforwards are 2019 through 2025. Utilization of $25.6 million of the net operating loss carryforwards will be subject to the annual

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limitations due to the ownership change limitations provided by the Internal Revenue Code of 1986, as amended. The annual limitations may result in expiration of the net operating loss before full utilization. At December 31, 2009 and 2008, the Company has recorded a valuation allowance of approximately $2.4 million against its deferred tax assets to reflect the estimated expiration of net operating loss carryforwards.

The Company has not provided United States income tax expense on earnings of its foreign subsidiaries, since the Company has reinvested or expects to reinvest the undistributed earnings indefinitely. At December 31, 2009, the undistributed earnings of the Company s foreign subsidiaries were approximately $146.2 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.

Effective January 1, 2007, the Company adopted new authoritative guidance surrounding accounting for uncertainty in income taxes. The Company has recognized no material adjustment to the liability for unrecognized income tax benefits. It is the Company s policy to recognize interest and applicable penalties related to uncertain tax positions in income tax expense.

The Company files income tax returns in the U.S. federal and various state and foreign jurisdictions. The number of years that are open under the statute of limitations and subject to audit varies depending on the tax jurisdiction. The Company remains subject to U.S. federal tax examinations for years after 2005.

The Company had approximately $11.0 million and $9.7 million of unrecorded tax benefits at December 31, 2009 and 2008, respectively, all of which would impact the Company s effective tax rate if recognized. The unrecorded tax benefits are not considered material to the Company s financial position.

(11) Stockholders Equity

In December 2009, the Company s Board of Directors authorized a new $350 million share repurchase program of the Company s common stock that will expire on December 31, 2011, replacing the previous repurchase program that was set to expire on December 31, 2009. Under this program, the Company may purchase shares through open market transactions at prices deemed appropriate by management. There was no common stock repurchased and retired during the year ended December 31, 2009. For the years ended December 31, 2008 and 2007, the Company purchased and retired 3,717,000 shares and 1,000,000 shares of its common stock, respectively, for an aggregate amount of approximately $103.8 million and $33.8 million, respectively.

On January 1, 2009, the Company retrospectively adopted ASC 470-20, which requires the proceeds from the issuance of exchangeable debt instruments to be allocated between a liability component (issued at a discount) and an equity component. As a result of the retrospective adoption of ASC 470-20, the stockholders equity previously stated as of December 31, 2008 increased by approximately $34.7 million (see note 8).

(12) Gain on Sale of Businesses

In November 2009, the Company sold four liftboats from its 145-ft. leg length class for approximately $7.7 million. As a result of this sale of these liftboats, the Company recorded a pre-tax gain of approximately $2.1 million for the year ended December 31, 2009.

On March 14, 2008, the Company completed the sale of 75% of its interest in SPN Resources. As part of this transaction, SPN Resources contributed an undivided 25% of its working interest in each of its oil and gas properties to a newly formed subsidiary and then sold all of its equity interest in the subsidiary. SPN Resources then effectively sold 66 2/3% of its outstanding membership interests. These two transactions generated cash proceeds of approximately $167.2 million and resulted in a pre-tax gain of approximately $37.1 million in 2008. SPN Resources operations constituted substantially all of the Company s oil and gas segment. Subsequent to March 14, 2008, the Company accounts for its remaining 33 1/3% interest in SPN Resources using the equity-method. The results of SPN Resources operations through March 14, 2008 were consolidated.

In August 2007, the Company sold the assets of a non-core drilling products and services business for approximately $16.3 million in cash and $2.0 million in an interest-bearing note receivable. As a result of this asset sale, the

Company recorded a pre-tax gain of approximately $7.5 million in 2007. As certain conditions were met during the year ended December 31, 2008, the Company received cash of approximately $6.0 million, which resulted in an additional pre-tax gain on the sale of the business of approximately $3.3 million.

The Company also sold the assets of its field management division in 2007 for approximately $1.8 million in cash. As certain conditions were met during the year ended December 31, 2008 in conjunction with the sale of this division, the Company received cash of $0.5 million, all of which resulted in an additional pre-tax gain on the sale of the business.

(13) Profit Sharing and Retirement Plans

The Company maintains a defined contribution profit sharing plan for employees who have satisfied minimum service requirements. Employees may contribute up to 75% of their earnings to the plans limited by the annual dollar limitations imposed by the Internal Revenue Service. The Company may provide a discretionary match, not to exceed 5% of an employee s salary. The Company made contributions of approximately $3.8 million, $4.0 million and $3.7 million in 2009, 2008 and 2007, respectively.

The Company has a non-qualified deferred compensation plan which allows certain highly compensated employees the option to defer up to 75% of their base salary, up to 100% of their bonus, and up to 100% of the cash portion of their performance share unit compensation to the plan. Payments are made to participants based on their annual enrollment elections 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 (see note 18). At December 31, 2009 and 2008, the liability of the Company to the participants was approximately $15.8 million and $8.3 million, respectively, and is recorded in other long-term liabilities, which reflects the accumulated participant deferrals and earnings (losses) as of that date. For the years ended December 31, 2009, 2008 and 2007, the Company recorded compensation expense of $2.8 million, ($2.8) million and $0.5 million, respectively, related to the earnings and losses of the deferred compensation plan liability. The Company makes contributions equal to the participant deferrals into various investments, principally life insurance that is invested in mutual funds similar to the participants elections. A change in market value of the investments and life insurance is reflected as an adjustment to the deferred compensation plan asset with an offset to other income (expense). At December 31, 2009 and 2008, the deferred contribution plan asset was approximately $12.4 million and $7.2 million, respectively, and is recorded in intangible and other long-term assets. For the years ended December 31, 2009, 2008 and 2007, the Company recorded other income (expense) of $0.6, ($4.0) million and $0.2 million, respectively, related to the earnings and losses of the deferred compensation plan assets.

The Company also has a supplemental executive retirement plan (SERP). The SERP provides retirement benefits to the Company s executive officers and certain other designated key employees. The SERP is an unfunded, non-qualified defined contribution retirement plan, and all contributions under the plan are unfunded credits to a notional account maintained for each participant. Under the SERP, the Company will generally make annual contributions to a retirement account based on age and years of service. During 2009 and 2008, the participants in the plan received contributions ranging from 5% to 25% of salary and annual cash bonus, which totaled approximately $2.2 million and $1.4 million, respectively. The Company may also make discretionary contributions to a participant s retirement account. In 2008, the Company made a discretionary contribution to the account of its chief executive officer in the amount of $10 million. The Company recorded $2.1 million and $11.3 million of compensation expense in general and administrative expenses for the years ended December 31, 2009 and 2008, respectively.

(14) Segment Information

Business Segments

During 2009, the Company renamed two of its segments in order to more accurately describe the markets and customers served by the businesses operating in each segment. The content of these segments has not changed. The Company currently has three reportable segments: subsea and well enhancement (formerly well intervention), drilling products and services (formerly rental tools), and marine. The subsea and well enhancement segment provides production-related services used to enhance, extend and maintain oil and gas production, which include mechanical wireline, hydraulic workover and snubbing, well control, coiled tubing, electric line, pumping and stimulation and wellbore evaluation services; well plug and abandonment services; and other oilfield services used to support drilling and production operations. The drilling products and services 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 on-site 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. During the year ended December 31, 2008, the Company sold 75% of its interest in SPN Resources (see note 4). SPN Resources operations constituted substantially all the oil and gas segment. Oil and gas eliminations represent products and services provided to the oil and gas segment by the Company s three other segments. Certain previously reported amounts have been reclassified to conform to the presentation in the current period.

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, 2009, 2008 and 2007 and for the years then ended is shown in the following tables (in thousands):

2009	Subsea and Well Enhancement	Drilling Products and Services	Marine	Unallocated	Consolidated Total
Revenues	$ 919,335	$426,876	$103,089	$	$1,449,300
Cost of services, rentals, and sales (exclusive of items shown separately below)	616,116	143,802	64,116		824,034
Depreciation, depletion, amortization and accretion	89,986	105,613	11,515		207,114
General and administrative	149,122	90,318	19,653		259,093
Reduction in the value of assets	212,527				212,527
Gain on sale of business			2,084		2,084
Income (loss) from operations	(148,416)	87,143	9,889		(51,384)
Interest expense, net				(50,906)	(50,906)
Interest income				926	926
Other expense				571	571
Losses from equity-method investments				(22,600)	(22,600)
Reduction in the value of equity-method investment				(36,486)	(36,486)
	$ (148,416)	$ 87,143	$ 9,889	$(108,495)	$ (159,879)

Income (loss) before income taxes					
Identifiable assets	$1,377,122	$759,418	$299,834	$ 80,291	$2,516,665
Capital expenditures	$ 99,551	$124,845	$ 66,881	$	$ 291,277

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2008	Subsea and Well Enhancement	Drilling Products and Services	Marine	Oil & Gas	Oil & Gas Eliminations & Unallocated	Consolid. Total
Revenues	$1,155,221	$550,939	$121,104	$ 55,072	$ (1,212)	$1,881,124
Cost of services, rentals, and sales (exclusive of items shown separately below)	633,127	178,563	74,830	12,986	(1,212)	898,294
Depreciation, depletion, amortization and accretion	72,169	90,459	10,073	2,799		175,500
General and administrative	163,622	97,624	12,558	8,780		282,584
Gain on sale of businesses	500	3,332		37,114		40,946
Income from operations	286,803	187,625	23,643	67,621		565,692
Interest expense, net					(46,684)	(46,684)
Interest income					2,975	2,975
Other income					(3,977)	(3,977)
Earnings from equity-method investments				24,373		24,373
Income before income taxes	$ 286,803	$187,625	$ 23,643	$ 91,994	$(47,686)	$ 542,379
Identifiable assets	$1,343,710	$762,848	$239,572	$121,583	$ 22,432	$2,490,145
Capital expenditures	$ 206,404	$193,297	$ 51,428	$ 2,732	$	$ 453,861

2007	Subsea and Well Enhancement	Drilling Products and Services	Marine	Oil & Gas	Oil & Gas Eliminations & Unallocated	Consolid. Total
Revenues	$761,015	$496,290	$127,898	$192,700	$ (5,436)	$1,572,467
Costs of services, rentals and sales (exclusive of items	419,818	156,731	60,432	66,580	(5,436)	698,125

shown separately below)						
Depreciation, depletion, amortization and accretion	49,786	70,042	8,861	59,152		187,841
General and administrative	118,657	87,442	10,592	11,455		228,146
Gain on sale of business		7,483				7,483
Income from operations	172,754	189,558	48,013	55,513		465,838
Interest expense, net					(48,436)	(48,436)
Interest income				1,219	1,443	2,662
Other income					189	189
Losses from equity-method investments				(2,940)		(2,940)
Income before income taxes	$172,754	$189,558	$ 48,013	$ 53,792	$(46,804)	$ 417,313
Identifiable assets	$996,946	$687,944	$200,623	$344,667	$ 25,115	$2,255,295
Capital expenditures	$145,061	$166,944	$ 19,200	$ 75,725	$ 3,588	$ 410,518

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Geographic Segments

The Company attributes revenue to various countries based on the location where services are performed or the destination of the drilling products or products sold. 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,	
	2009	2008	2007	2009	2008
United States	$1,126,071	$1,564,384	$1,273,705	$ 828,662	$ 938,453
Other Countries	323,229	316,740	298,762	230,314	176,488
Total	$1,449,300	$1,881,124	$1,572,467	$1,058,976	$1,114,941

(15) Guarantee

As part of SPN Resources acquisition of its oil and gas properties, the Company guaranteed SPN Resources performance of its decommissioning liabilities. In accordance with Accounting Standards Codification 460-10, Guarantees, the Company has assigned an estimated value of $2.7 and $2.9 million at December 31, 2009 and 2008, respectively, related to decommissioning performance guarantees, which is reflected in other long-term liabilities. The Company believes that the likelihood of being required to perform these guarantees is remote. In the unlikely event that SPN Resources defaults on the decommissioning liabilities existing at the closing date, the total maximum potential obligation under these guarantees is estimated to be approximately $114.2 million, net of the contractual right to receive payments from third parties, which is approximately $26.9 million, as of December 31, 2009. The total maximum potential obligation will decrease over time as the underlying obligations are fulfilled by SPN Resources.

(16) Commitments and Contingencies

The Company leases many of its office, service and assembly facilities under operating leases. In addition, the Company also leases certain assets used in providing services under operating leases. The leases expire at various dates over an extended period of time. Total rent expense was approximately $12.0 million, $10.3 million and $7.8 million in 2009, 2008 and 2007, respectively. Future minimum lease payments under non-cancelable leases for the five years ending December 31, 2010 through 2014 and thereafter are as follows (amounts in thousands): $13,191, $7,609, $4,609, $2,654, $2,221 and $14,434, respectively.

Due to the nature of the Company s business, the Company is involved, from time to time, in routine litigation or subject to disputes or claims regarding our business activities. Legal costs related to these matters are expensed as incurred. In management s opinion, none of the pending litigation, disputes or claims will have a material adverse effect on the Company s financial condition, results of operations or liquidity.

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(17) Interim Financial Information (Unaudited)

The following is a summary of consolidated interim financial information for the years ended December 31, 2009 and 2008 (amounts in thousands, except per share data).

	Three Months Ended			
2009	March 31	June 30	Sept. 30	Dec. 31
Revenues	$ 437,109	$ 361,161	$ 386,455	$ 264,575
Less:				
Cost of services, rentals and sales	222,465	197,268	215,674	188,627
Depreciation, depletion, amortization and accretion	49,868	50,978	52,720	53,548
Gross profit	164,776	112,915	118,061	22,400
Net income (loss)	56,805	(68,917)	24,419	(114,630)
Earnings (loss) per share:				
Basic	$ 0.73	$ (0.88)	$ 0.31	$ (1.46)
Diluted	0.72	(0.88)	0.31	(1.46)

	Three Months Ended			
2008	March 31	June 30	Sept. 30	Dec. 31
Revenues	$ 441,391	$ 457,655	$ 490,282	$ 491,796
Less:				
Cost of services, rentals and sales	204,118	222,097	236,610	235,469
Depreciation, depletion, amortization and accretion	41,879	41,954	44,842	46,825
Gross profit	195,394	193,604	208,830	209,502
Net income	99,529	71,367	97,294	83,285
Earnings per share:				
Basic	$ 1.23	$ 0.88	$ 1.21	$ 1.07
Diluted	1.21	0.86	1.19	1.06

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(18) Fair Value Measurements

In January 2008, the Company adopted Accounting Standards Codification 820-10 (ASC 820-10), Fair Value Measurements and Disclosures, for its financial assets and liabilities. The adoption of ASC 820-10 did not have a material impact on its fair value measurements.

ASC 820-10 establishes a fair value framework requiring the categorization of assets and liabilities into three levels based upon the assumptions (inputs) used to price the assets and liabilities. Level 1 provides the most reliable measure of fair value, whereas Level 3 generally requires significant management judgment. The three levels are defined as follows:

Level 1: Unadjusted quoted prices in active markets for identical assets and liabilities.

Level 2: Observable inputs other than those included in Level 1 such as quoted prices for similar assets and liabilities in active markets; quoted prices for identical assets or liabilities in inactive markets or model-derived valuations or other inputs that can be corroborated by observable market data.

Level 3: Unobservable inputs reflecting management s own assumptions about the inputs used in pricing the asset or liability.

The following table provides a summary of the financial assets and liabilities measured at fair value on a recurring basis at December 31, 2009 and December 31, 2008 (in thousands):

		Fair Value Measurements at Reporting Date Using		
	December 31, 2009	(Level 1)	(Level 2)	(Level 3)
Non-qualified deferred compensation plan assets	$ 12,382	$ 4,586	$ 7,796	$
Non-qualified deferred compensation plan liabilities	$ 15,758	$	$ 15,758	$

		Fair Value Measurements at Reporting Date Using		
	December 31, 2008	(Level 1)	(Level 2)	(Level 3)
Non-qualified deferred compensation plan assets	$ 7,212	$	$ 7,212	$
Non-qualified deferred compensation plan liabilities	$ 8,254	$	$ 8,254	$

The Company s non-qualified deferred compensation plan allows officers and highly compensated employees to defer receipt of a portion of their compensation and contribute such amounts to one or more hypothetical investment funds (see note 13). The Company entered into a separate trust agreement, subject to general creditors, to segregate the assets of the plan and it reports the accounts of the trust in its condensed consolidated financial statements. These investments are reported at fair value based on unadjusted quoted prices in active markets for identifiable assets and observable inputs for similar assets and liabilities, which represents Levels 1 and 2, respectively in the ASC 820-10 fair value hierarchy. The realized and unrealized holding gains and losses related to non-qualified deferred compensation assets are recorded as other income (expense). The realized and unrealized holding gains and losses related to non-qualified deferred compensation liabilities are recorded in general and administrative expenses.

In January 2009, the Company adopted ASC 820-10 for its non-financial assets and non-financial liabilities that are remeasured at fair value on a non-recurring basis. In accordance with ASC 360-10, long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. During the year ended December 31, 2009, due to continued decline in demand for services in the domestic land markets, the Company identified impairments of certain long-lived assets of approximately $212.5 million (see note 3). Additionally, during 2009, the Company recorded a $36.5 million reduction in the value of its equity-method investment in BOG. In April 2009, BOG defaulted under its loan agreements due primarily to the impact of pipeline curtailments from Hurricanes Gustav and Ike in 2008 and the decline of natural gas and oil prices. As a result of continued negative BOG operating results, lack of viable interested buyers and unsuccessful attempts to renegotiate the terms and conditions of its loan agreements with lenders on terms that would preserve the Company s investment, the Company wrote off the remaining carrying value of its investment in BOG (see note 7).

The following table reflects the fair value measurements used in testing the impairment of long-lived assets and equity-method investments during the year ended December 31, 2009 (in thousands):

		Fair Value Measurements at Reporting Date Using			
	December 31, 2009	(Level 1)	(Level 2)	(Level 3)	Total Losses
Property, plant and equipment, net	$107,591			$ 107,591	$(119,844)
Intangible and other long-term assets, net	$ - 0 -			$ - 0 -	$ (92,683)
Equity-method investments	$ - 0 -			$ - 0 -	$ (36,486)

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

On March 14, 2008, the Company completed the sale of 75% of its interest in SPN Resources. As part of this transaction, SPN Resources contributed an undivided 25% of its working interest in each of its oil and gas properties to a newly formed subsidiary and then sold all of its equity interest in the subsidiary. SPN Resources then effectively sold 66 2/3% of its outstanding membership interests. SPN Resources operations constituted substantially all of the Company s oil and gas segment. Subsequent to March 14, 2008, the Company accounts for its remaining 33 1/3% interest in SPN Resources using the equity-method. Prior to the sale of 75% of its interest in SPN Resources, the results of SPN Resources operations through March 14, 2008 were consolidated (see note 4).

The Company s December 31, 2007 estimates of proved reserves are based on reserve reports prepared by DeGolyer and MacNaughton, independent petroleum engineers. 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.

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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, 2006	7,921	35,641
Purchase of reserves in place and additions	1,206	6,862
Revisions	519	1,688
Production	(1,817)	(8,931)
December 31, 2007	7,829	35,260
Proved developed reserves:		
December 31, 2007	6,493	34,742

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).

Costs incurred for oil and natural gas property acquisition and development activities for the year ended December 31, 2007 are as follows (in thousands):

Acquisition of properties proved	$ 12,126
Development costs	76,928
Total costs incurred	$ 89,054

Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves

The following information has been developed utilizing procedures prescribed by Accounting Standards Codification 932 (ASC 932), Extractive Activities Oil and Gas. 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 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 ASC 932.

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The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves at December 31, 2007 is as follows (in thousands):

Future cash inflows	$ 1,043,327
Future production costs	(207,749)
Future development and abandonment costs	(251,071)
Future income tax expense	(167,305)
Future net cash flows after income taxes	417,202
10% annual discount for estimated timing of cash flows	57,534
Standardized measure of discounted future net cash flows	$ 359,668

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 year ended December 31, 2007 is as follows (in thousands):

Beginning of the period	$ 178,742
Sales and transfers of oil and natural gas produced, net of production costs	(130,130)
Net changes in prices and production costs	247,708
Revisions of quantity estimates	41,479
Development costs incurred	(77,239)
Changes in estimated development costs	28,761
Extensions and discoveries	106,055
Purchase and sales of reserves in place	15,667
Changes in production rates (timing) and other	12,545
Accretion of discount	21,247
Net change in income taxes	(85,167)
Net increase	180,926
End of period	$ 359,668

The December 31, 2007 amount was estimated by DeGolyer and MacNaughton using a period-end NYMEX crude price of $95.98 per barrel (bbl), a NYMEX gas price of $7.48 per million British Thermal Units, and price differentials provided by the Company.

(20) Subsequent Events

On January 26, 2010, the Company acquired 100% of the equity interest of Hallin, for approximately $162.3 million. Additionally, the Company repaid approximately $55.2 million of Hallin s debt. Hallin is an international provider of integrated subsea services and engineering solutions, focused on installing, maintaining and extending the life of subsea wells. Hallin operates in international offshore oil and gas markets with offices and facilities located in Singapore; Jakarta, Indonesia; Perth, Australia; Aberdeen, Scotland; and Houston, Texas (see note 4).

On January 31, 2010, the Company acquired 100% ownership of Shell s Gulf of Mexico Bullwinkle platform and related assets, and assumed the decommissioning obligations for such assets. Immediately after the Company acquired these assets, it sold an undivided 49% interest in them to Dynamic Offshore Resources, LLC, which will generate the assets. The Company will plug and abandon the 29 wells associated with Bullwinkle, which is the deepest fixed-leg production platform on the Outer Continental Shelf. The Bullwinkle platform will be decommissioned at the end of its economic life (see note 4).

In May 2009, the Financial Accounting Standards Board issued Accounting Standards Codification 855-10 (ASC 855-10), Subsequent Events, which establishes general standards of accounting for, and disclosure of, events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. In accordance with ASC 855-10, the Company has evaluated and disclosed all material subsequent events that occurred after the balance sheet date, but before financial statements were issued.

(21) Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board issued Accounting Standards Update No. 2009-01 (ASC Topic 105), Generally Accepted Accounting Principles, which establishes the FASB Accounting Standards Codification (the Codification or ASC) as the official single source of authoritative U.S. generally accepted accounting principles (GAAP). All existing accounting standards are superseded. All other accounting guidance not included in the Codification is considered non-authoritative. The Codification also includes all relevant Securities and Exchange Commission guidance organized using the same topical structure in separate sections within the Codification. Following the Codification, the Board will not issue new standards in the form of Statements, FASB Staff Positions or Emerging Issues Task Force Abstracts. Instead, it will issue Accounting Standards Updates which will serve to update the Codification, provide background information about the guidance and provide the basis for conclusions on the changes to the Codification. The Codification is not intended to change GAAP, but it changes the way GAAP is organized and presented. The Codification is effective for financial statements issued for interim and annual periods ending after September 15, 2009 and the principal impact on the Company s financial statements is limited to disclosures as all current and future references to authoritative accounting literature will be referenced in accordance with the Codification.

In June 2009, the Financial Accounting Standards Board issued its Accounting Standards Codification 810-10 (ASC 810-10), Amendments to FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities, for determining whether an entity is a variable interest entity (VIE) and requires an enterprise to perform an analysis to determine whether the enterprise s variable interest or interests give it a controlling financial interest in a VIE. ASC 810-10 also requires ongoing assessments of whether an enterprise is the primary beneficiary of a VIE, requires enhanced disclosures and eliminates the scope exclusion for qualifying special-purpose entities. ASC 810-10 is effective for annual reporting periods beginning after November 15, 2009. The Company is currently evaluating the impact the adoption of ASC 810-10 will have on its results of operations and financial position.

In October 2009, the Financial Accounting Standards Board issued Accounting Standards Update 2009-13 (ASU 2009-13), Multiple-Deliverable Revenue Arrangements. The new standard changes the requirements for establishing separate units of accounting in a multiple element arrangement and requires the allocation of arrangement consideration to each deliverable based on the relative selling price. The selling price for each deliverable is based on vendor-specific objective evidence (VSOE) if available, third-party evidence if VSOE is not available, or estimated selling price if neither VSOE or third-party evidence is available. ASU 2009-13 is effective for revenue arrangements entered into in fiscal years beginning on or after June 15, 2010. The Company is currently evaluating the impact the adoption of ASU 2009-13 will have on its results of operations and financial position.

In January 2010, the Financial Accounting Standards Board issued Accounting Standards Update 2010-06 (ASU 2010-06), Improving Disclosures about Fair Value Measurements. The update provides an amendment to ASC 820-10, Fair Value Measurements and Disclosures, requiring additional disclosures of significant transfers between Level 1 and Level 2 within the fair value hierarchy as well as information about purchases, sales, issuances and settlements using unobservable inputs (Level 3). ASU 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009 for new disclosures and clarifications of existing disclosures, except for disclosures about purchases, sales, issuances and settlements in the rollforward of activity in the Level 3 fair value measurements, which are effective for fiscal years beginning after December 15, 2010. The Company is currently evaluating the impact the adoption of ASU 2010-06 will have on its disclosures within its financial statements.

In January 2010, the Financial Accounting Standards Board issued Accounting Standards Update 2010-03 (ASU 2010-03), Oil and Gas Reserve Estimation and Disclosures. The update provides an amendment to Accounting Standards Codification 932 (ASC 932), Extractive Activities Oil and Gas, that expands the definition of oil- and gas-producing activities and requires disclosures of reserve quantities and standardized measure of cash flows for equity-method investments that have significant oil- and gas-producing activities. ASU 2010-03 is effective for annual reporting periods ending on or after December 31, 2009. ASU 2010-03 allows an entity that becomes subject to the disclosure requirements of ASC 932 due to the change to the definition of significant oil- and gas-producing activities to apply the disclosure provisions of ASC 932 in annual periods beginning after December 31, 2009. As such, the Company has elected to defer the application of ASU 2010-03 until the annual reporting period ended December 31, 2010. The Company is currently evaluating the impact the adoption of ASU 2010-03 will have on its results of operations and financial position.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Our management has established and maintains a system of disclosure controls and procedures to provide reasonable assurances that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is appropriately recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission (SEC). In addition, the disclosure controls and procedures ensure that information required to be disclosed, accumulated and communicated to management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), allow timely decisions regarding required disclosure. An evaluation was carried out, under the supervision and with the participation of our management, including our CEO and CFO, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-14(e) and Rule 15d-15(e) of the Securities Exchange Act of 1934) as of the end of the period covered by this report. Based on that evaluation, our principal executive and financial officers have concluded that our disclosure controls and procedures as of December 31, 2009 were effective to provide reasonable assurance that information required to be disclosed by us in reports we file with the SEC is recorded, processed, summarized and reported within the time periods required by the SEC s rules and forms, and is accumulated and communicated to management, including our CEO and CFO, as appropriate, to allow timely decisions regarding disclosures. Management s report and the independent registered public accounting firm s attestation report are included herein under the captions Management s Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm, and are incorporated by reference.

There has been no change in our internal control over financial reporting during the three months ended December 31, 2009, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over our financial reporting, and for performing an assessment of the effectiveness of internal control over our financial reporting as of December 31, 2009. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Our system of internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements. Management recognizes that there are inherent limitations in the effectiveness of any internal control over financial reporting, including the possibility of human error and the circumvention or overriding of internal control. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may be inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management, including our principal executive officer and principal financial officer, performed an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2009 based upon criteria in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, our management determined that as of December 31, 2009, our internal control over financial reporting was effective based on those criteria.

Our internal control over financial reporting as of December 31, 2009 has been audited by KPMG, LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Report of Independent Registered Public Accounting Firm

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

We have audited Superior Energy Services, Inc. s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Superior Energy Services, Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Superior Energy Services, Inc. s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Superior Energy Services, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Superior Energy Services, Inc. and subsidiaries as of December 31, 2009 and 2008, 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, 2009, and our report dated February 26, 2010 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP
New Orleans, Louisiana
February 26, 2010

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Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information relating to our executive officers is included in Part I, Item 4A, and is incorporated herein by reference. Information relating to our Code of Business Ethics and Conduct that applies to our senior financial officers is included in Part I, Item 1, and is incorporated herein by reference. Other information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

Information required by this item will be contained in our definitive proxy statement to be filed pursuant to Regulation 14A and is incorporated herein by reference.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) (1) Financial Statements

The following financial statements are included in Part II of this Annual Report on Form 10-K:

Report of Independent Registered Public Accounting Firm Audit of Financial Statements
Consolidated Balance Sheets December 31, 2009 and 2008
Consolidated Statements of Operations for the years ended December 31, 2009, 2008 and 2007
Consolidated Statements of Changes in Stockholders Equity for the years ended December 31, 2009, 2008 and 2007
Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007
Notes to Consolidated Financial Statements
Management s Report on Internal Control over Financial Reporting
Report of Independent Registered Public Accounting Firm Audit of Internal Control over Financial Reporting

(2) Financial Statement Schedule

Schedule II Valuation and Qualifying Accounts for the years ended December 31, 2009, 2008 and 2007

Separate financial statements for DBH, LLC.:
Independent Auditors Report
Consolidated Balance Sheet as of December 31, 2009
Consolidated Statements of Operations for the period from January 1 through October 12, 2009 (predecessor) and for the period from October 13 through December 31, 2009
Consolidated Statements of Cash Flows for the period from January 1 through October 12, 2009 (predecessor) and for the period from October 13 through December 31, 2009
Consolidated Statement of Members Equity/Partners Capital for the period from January 1 through October 12, 2009 (predecessor) and for the period from October 13 through December 31, 2009
Notes to Consolidated Financial Statements
Supplemental Information (Unaudited)

Separate financial statements for Beryl Oil and Gas LP (Unaudited):
Balance Sheet as of December 31, 2008 and 2007
Statements of Operations for the years ended December 31, 2008 and 2007
Statements of Partners Capital for the years ended December 31, 2008 and 2007
Statement of Cash Flows for the years ended December 31, 2008 and 2007
Notes to Financial Statements
Supplemental Information
All other schedules are omitted because they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

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(3) Exhibits

Exhibit No.	Description
2.1	Implementation Agreement, dated December 11, 2009 by and among Superior Energy Services, Inc., Superior Energy Services (UK) Limited and Hallin Marine Subsea International Plc. (incorporated herein by reference to Exhibit 2.1 the Company s Form 8-K filed December 11, 2009).
2.2	Rule 2.5 Announcement (incorporated herein by reference to Exhibit 2.2 the Company s Form 8-K filed December 11, 2009).
3.1	Certificate of Incorporation of the Company (incorporated herein by reference to the Company s Quarterly Report on Form 10-QSB for the quarter ended March 31, 1996 (File No. 000-20310)).
3.2	Amended and Restated Bylaws of the Company (as amended through September 12, 2007) (incorporated herein by reference to Exhibit 3.11 to the Company s Form 8-K filed on September 18, 2007).
3.3	Certificate of Amendment to the Company s Certificate of Incorporation (incorporated herein by reference to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 1999 (File No. 333-22603)).
4.1	Specimen Stock Certificate (incorporated herein by reference to Amendment No. 1 to the Company s Form S-4 on Form SB-2 (Registration Statement No. 33-94454)).
4.2	Indenture, dated May 22, 2006, among the Company, SESI, L.L.C., the guarantors identified therein and The Bank of New York Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.2 to the Company s Form 8-K filed May 23, 2006), as amended by Supplemental Indenture, dated December 12, 2006, by and among Warrior Energy Services Corporation, SESI, L.L.C., the other Guarantors (as defined in the Indenture referred to therein) and The Bank of New York Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to the Company s 8-K filed December 13, 2006 for the period beginning December 12, 2006), as further amended by Supplemental Indenture, dated September 13, 2007 but effective as of August 29, 2007, by and among AOS, SESI, the other Guarantors (as defined in the Indenture referred to therein) and the Trustee (incorporated herein by reference to Exhibit 4.1 to the Company s Form 8-K filed on September 18, 2007).

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Exhibit No.	Description
4.3	Indenture, dated December 12, 2006, by and among the Company, SESI, L.L.C., the guarantors named therein and The Bank of New York Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to the Company s Form 8-K filed December 13, 2006 for the period beginning December 7, 2006), as amended by Supplemental Indenture, dated December 12, 2006, by and among Warrior Energy Services Corporation, SESI, L.L.C., the other Guarantors (as defined in the Indenture referred to therein) and The Bank of New York Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.2 to the Company s Form 8-K filed December 13, 2006 for the period beginning December 12, 2006), as further amended by Supplemental Indenture, dated September 13, 2007 but effective as of August 29, 2007, by and among AOS, SESI, the other Guarantors (as defined in the Indenture referred to therein) and the Trustee (incorporated herein by reference to Exhibit 4.2 to the Company s Form 8-K filed on September 18, 2007).
10.1^	Amended and Restated Superior Energy Services, Inc. 1995 Stock Incentive Plan (incorporated herein by reference to Exhibit A to the Company s Definitive Proxy Statement dated June 25, 1997 (File No. 000-20310)).
10.2	Wreck Removal Contract, dated December 31, 2007, by and among Wild Well Control, Inc., BP America Production Company, Chevron U.S.A. Inc. and GOM Shelf LLC (The Company agrees to furnish supplementally a copy of any omitted exhibits to the SEC upon request) (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on January 4, 2008).
10.3^	Employment Agreement between Superior Energy Services, Inc. and Patrick J. Zuber, dated January 1, 2008 (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on January 7, 2008).
10.4^	Form of Employment Agreement for Kenneth L. Blanchard and Robert S. Taylor (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on June 6, 2007).
10.5^	Superior Energy Services, Inc. 2007 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on May 24, 2007).
10.6^	Form of Employment Agreement executed by Superior Energy Services, Inc. and each of Alan P. Bernard, Lynton G. Cook, III, James A. Holleman and Danny R. Young (incorporated herein by reference to Exhibit 10.2 to the Company s Form 8-K filed on June 6, 2007).
10.7^	Employment Agreement between Superior Energy Services, Inc. and Charles Hardy, dated January 1, 2008 (incorporated herein by reference to Exhibit 10.2 to the Company s Form 8-K filed on January 7, 2008).

Exhibit No.	Description
10.8^	Superior Energy Services, Inc. 1999 Stock Incentive Plan (incorporated herein by reference to the Company s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 333-22603)), as amended by Second Amendment to Superior Energy Services, Inc. 1999 Stock Incentive Plan, effective as of December 7, 2004 (incorporated herein by reference to Exhibit 10.2 to the Company s Form 8-K filed on December 20, 2004 (File No. 333-22603)).
10.9^	Employment Agreement between the Company and Terence E. Hall (incorporated herein by reference to the Company s Annual Report on Form 10-K for the year ended December 31, 1999 (File No. 333-22603)), as amended by Letter Agreement dated November 12, 2004 between the Company and Terence E. Hall (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on November 15, 2004 (File No. 333-22603)), as amended by Amendment No. 2 to Amended and Restated Employment Agreement dated as of December 29, 2008, between the Company and Terence E. Hall (incorporated herein by reference to Item 10.1 to the Company s Form 8-K filed January 2, 2009).
10.10^	Amended and Restated Superior Energy Services, Inc. 2002 Stock Incentive Plan (incorporated herein by reference to the Company s Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 333-22603)), as amended by First Amendment to Superior Energy Services, Inc. 2002 Stock Incentive Plan, effective as of December 7, 2004 (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed on December 20, 2004 (File No. 333-22603)).
10.11*^	Superior Energy Services, Inc. Nonqualified Deferred Compensation Plan.
10.12^	Superior Energy Services, Inc. 2005 Stock Incentive Plan (incorporated herein by reference to Appendix A to the Company s Definitive Proxy Statement dated April 18, 2005).
10.13^	Amended and Restated Superior Energy Services, Inc. 2004 Directors Restricted Stock Units Plan (incorporated herein by reference to Appendix B to the Company s Definitive Proxy Statement dated April 20, 2006).
10.14	Confirmation of OTC Exchangeable Note Hedge, dated December 7, 2006, by and between SESI, L.L.C. and Bear, Stearns International, Limited (incorporated herein by reference to Exhibit 10.3 to the Company s Form 8-K filed December 13, 2006 for the period beginning December 7, 2006).
10.15	Confirmation of OTC Exchangeable Note Hedge, dated December 7, 2006, by and between SESI, L.L.C. and Lehman Brothers OTC Derivatives Inc. (incorporated herein by reference to Exhibit 10.4 to the Company s Form 8-K filed December 13, 2006 for the period beginning December 7, 2006).
10.16	Confirmation of OTC Warrant Confirmation, dated December 7, 2006, by and between the Company and Bear, Stearns International, Limited (incorporated herein by reference to Exhibit 10.5 to the Company s Form 8-K filed December 13, 2006 for the period beginning December 7, 2006).

Exhibit No.	Description
10.17	Confirmation of OTC Warrant Confirmation, dated December 7, 2006, by and between the Company and Lehman Brothers OTC Derivatives Inc. (incorporated herein by reference to Exhibit 10.6 to the Company s Form 8-K filed December 13, 2006 for the period beginning December 7, 2006).
10.18	Purchase, Contribution and Redemption Agreement, dated February 25, 2008, by and among Dynamic Offshore Resources, LLC, Moreno Group LLC, SESI, LLC, and SPN Resources, LLC (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed February 29, 2008).
10.19^	Employment Agreement, dated March 1, 2008, by and between Superior Energy Services, Inc. and William B. Masters (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed March 6, 2008).
10.20^	Letter agreement between Superior Energy Services, Inc. and Patrick J. Zuber, dated December 22, 2008 (incorporated herein by reference to the Company s Annual Report on Form 10-K for the year ended December 31, 2008).
10.21*^	Superior Energy Services, Inc. Supplemental Executive Retirement Plan.
10.22^	Superior Energy Services, Inc. 2009 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed on May 27, 2009).
10.23^	Employment Agreement between Superior Energy Services, Inc. and Patrick J. Campbell, dated March 30, 2009 (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed April 2, 2009).
10.24	Second Amended and Restated Credit Agreement dated May 29, 2009 among Superior Energy Services, Inc., SESI, L.L.C., JPMorgan Chase Bank, N.A. and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed June 1, 2009).
10.25^	Form of Stock Option Agreement under the Superior Energy Services, Inc. 2005 Stock Incentive Plan and the 2009 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed December 16, 2009).
10.26^	Form of Restricted Stock Agreement under the Superior Energy Services, Inc. 2005 Stock Incentive Plan and the 2009 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed December 16, 2009).
10.27^	Form of Performance Share Unit Award Agreement under the Superior Energy Services, Inc. 2005 Stock Incentive Plan and the 2009 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Company s Form 8-K filed December 16, 2009).
14.1	Code of business ethics and conduct (incorporated herein by reference to the Company s Annual Report on Form 10-K for the year ended December 31, 2003 (File No. 333-22603)).
21.1*	Subsidiaries of the Company.

23.1*	Consent of KPMG LLP, independent registered public accounting firm.

Exhibit No.	Description
23.2*	Consent of Hein & Associates LLP, independent registered public accounting firm.
23.3*	Consent of DeGoyler and MacNaughton
31.1*	Officer s certification pursuant to Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934, as amended.
31.2*	Officer s certification pursuant to Rules 13a-14(a) and 15d-14(a) under the Securities Exchange Act of 1934, as amended.
32.1*	Officer s certification pursuant to Section 1350 of Title 18 of the U.S. Code.
32.2*	Officer s certification pursuant to Section 1350 of Title 18 of the U.S. Code.

* Filed herein

^ Management contract or compensatory plan or arrangement.

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SIGNATURES

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: February 26, 2010

By: /s/ Terence E. Hall
Terence E. Hall
Chairman of the Board and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Terence E. Hall **Terence E. Hall**	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	February 26, 2010
/s/ Robert S. Taylor **Robert S. Taylor**	Executive Vice President, Treasurer and Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2010
/s/ Harold J. Bouillion **Harold J. Bouillion**	Director	February 26, 2010
/s/ Enoch L. Dawkins **Enoch L. Dawkins**	Director	February 26, 2010
/s/ James M. Funk **James M. Funk**	Director	February 26, 2010
/s/ Ernest E. Howard, III **Ernest E. Howard, III**	Director	February 26, 2010
/s/ Justin L. Sullivan **Justin L. Sullivan**	Director	February 26, 2010

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES
Schedule II Valuation and Qualifying Accounts
Years Ended December 31, 2009, 2008 and 2007
(in thousands)

Description	Balance at the beginning of the year	Additions: Charged to costs and expenses	Additions: Balances from acquisitions	Deductions	Balance at the end of the year
Year ended December 31, 2009:					
Allowance for doubtful accounts	$ 18,013	$ 10,866	$	$ 5,200	$ 23,679
Year ended December 31, 2008:					
Allowance for doubtful accounts	$ 16,742	$ 6,471	$	$ 5,200	$ 18,013
Year ended December 31, 2007:					
Allowance for doubtful accounts	$ 17,419	$ 3,833	$ 404	$ 4,914	$ 16,742

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DBH, LLC

Consolidated Financial Statements and
Supplemental Information (Unaudited)
December 31, 2009
(With Independent Auditors Report Thereon)

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DBH, LLC
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Independent Auditor s Report

To the Members of
DBH, LLC

We have audited the accompanying consolidated balance sheet of DBH, LLC (the Company) as of December 31, 2009, and the related consolidated statements of operations, cash flows and members equity/partners capital for the period from January 1 through October 12, 2009 (predecessor period) and for the period from October 13 through December 31, 2009. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. 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 audit provides 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 DBH, LLC as of December 31, 2009 and the results of its operations and its cash flows for the period from January 1 through October 12, 2009 (predecessor period) and for the period from October 13 through December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

/s/ Hein & Associates LLP
Hein & Associates LLP
Houston, Texas
February 24, 2010

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DBH, LLC
CONSOLIDATED BALANCE SHEET
DECEMBER 31, 2009
(In thousands)

Assets	
Current assets:	
Cash and cash equivalents	$ 43,928
Accounts receivable	13,556
Insurance receivable	33,300
Assets from risk management activities	1,763
Other current assets	7,931
Total current assets	100,478
Property and equipment:	
Oil and gas properties, successful efforts method	311,465
Accumulated depreciation, depletion, and amortization	(8,510)
Property and equipment, net	302,955
Other assets	6,945
Total assets	$ 410,378
Liabilities and Members Equity	
Current liabilities:	
Accounts payable third parties	$ 6,115
Accounts payable affiliates	2,848
Accrued liabilities	19,716
Current portion of asset retirement obligations	19,113
Total current liabilities	47,792
Long-term debt	105,000
Asset retirement obligations, net of current portion	56,676
Long-term liabilities from risk management activities	1,145
Other long-term liabilities	5,492
Total liabilities	216,105
Commitments and contingencies (see Note 12)	
Members equity	194,273
Total liabilities and members equity	$ 410,378

See notes to consolidated financial statements

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DBH, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands)

	DBH, LLC October 13 through December 31, 2009	Predecessor January 1 through October 12, 2009
Oil and gas revenues	$ 27,439	$ 89,599
Costs and expenses:		
Lease operating expenses	7,923	33,640
Exploration expenses	2,159	330
Depreciation, depletion and amortization	8,510	89,046
General and administrative expenses	3,983	17,523
Other operating expenses	5,232	18,537
Total operating costs and expenses	27,807	159,076
Loss from operations	(368)	(69,477)
Other income (expense):		
Interest expense, net	(2,197)	(22,411)
Gain on mark-to-market derivatives	667	24,132
Gain on acquisition of Bandon Oil and Gas, LP	160,877	
Net income (loss)	$ 158,979	$ (67,756)

See notes to consolidated financial statements

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DBH, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	DBH, LLC October 13 through December 31, 2009	Predecessor January 1 through October 12, 2009
Cash flows from operating activities:		
Net income (loss)	$ 158,979	$ (67,756)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	16	1,934
Accretion of asset retirement obligation	950	4,496
Other depreciation, depletion and amortization	8,510	89,045
Risk management activities	(619)	15,471
Gain on sale of assets	(43)	(22)
Loss on settlement of asset retirement obligations		1,391
Gain on acquisition of Bandon Oil and Gas, LP	(160,877)	
Changes in operating assets and liabilities:		
Accounts receivable and other assets	7,975	(27,506)
Accounts payable and other liabilities	(4,218)	8,819
Net cash provided by operating activities	10,673	25,872
Cash flows from investing activities:		
Additions to property and equipment	(3,703)	(65,197)
Acquisition of Bandon Oil and Gas, LP, net of cash acquired	40,524	
Proceeds from sale of property and equipment	42	300
Derivative settlements	12,615	
Other, net		(1,032)
Net cash provided by (used in) investing activities	49,478	(65,929)
Cash flows from financing activities:		
Repayment of long-term debt	(46,223)	(300)
Contributions	32,160	
Repurchase of member interest	(2,160)	
Net cash used in financing activities	(16,223)	(300)
Net increase (decrease) in cash and cash equivalents	43,928	(40,357)
Cash and cash equivalents, beginning of period		80,881
Cash and cash equivalents, end of period	$ 43,928	$ 40,524

Supplemental cash flow disclosures:				
Interest paid	$	2,191	$	15,355

See notes to consolidated financial statements

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DBH, LLC
CONSOLIDATED STATEMENT OF MEMBERS EQUITY/PARTNERS CAPITAL
(In thousands)

	Predecessor
Balance at December 31, 2008	$ 144,904
Net loss	(67,756)
Other comprehensive income (loss):	
Reclassification adjustments for settled periods:	
Commodity hedges	1,487
Interest rate hedges	(11,618)
Total other comprehensive loss	(10,131)
Comprehensive loss	(77,887)
Balance at October 12, 2009	$ 67,017

	DBH, LLC
Non-cash contribution of asset (see Note 4)	$ 5,294
Cash contributions	32,160
Repurchase of member interest	(2,160)
Net income	158,979
Balance at December 31, 2009	$ 194,273

See notes to consolidated financial statements

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DBH, LLC
Notes to Consolidated Financial Statements

Except as noted within the context of each footnote disclosure and the unaudited supplemental information, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1 Organization and Basis of Presentation

DBH, LLC (the Company) which changed its name from Dynamic Beryl Holdings, LLC in January 2010 is a Delaware limited liability company that was formed on September 24, 2009 to acquire and own Bandon Oil and Gas, LP and Bandon Oil and Gas GP, LLC (collectively, Bandon). As a limited liability company, the Company is solely responsible for the debts, obligations and liabilities of the Company and no member or manager of the Company is obligated personally for any such debt, obligation or liability of the Company.

The Company s only significant asset is its ownership of 100% of Bandon. Bandon, which changed its name from Beryl Oil and Gas LP in January 2010, was organized in May 2006 for the purpose of acquiring oil and gas properties offshore Texas and Louisiana in the Gulf of Mexico.

The Company acquired Bandon on October 13, 2009 (the acquisition date). Prior to October 13, 2009, Bandon was owned by Beryl Resources LP (BR) and Superior Energy Services, Inc. (SESI), and is presented in these consolidated financial statements as Predecessor .

The Company accounted for its acquisition of Bandon using the acquisition method, under which 100% of Bandon s assets and liabilities were recorded at fair value as of the acquisition date. This has resulted in a new basis of accounting reflecting the fair value of Bandon s assets and liabilities for the successor period beginning October 13, 2009. Information for the period prior to the Company s acquisition of Bandon is presented using Bandon s historical basis of accounting. As a result of the application of the acquisition method, the predecessor period is not comparable to the successor period.

The accompanying consolidated financial statements present the Company s consolidated financial position as of December 31, 2009; its consolidated results of operations, cash flows and changes in members equity for the period from October 13 through December 31, 2009, and the results of operations, cash flows and changes in partners capital of the Predecessor for the period from January 1 through October 12, 2009. The Company s financial data has been further separated from the Predecessor financial data by a bold black line to indicate the effective date of the new basis of accounting.

The accompanying consolidated financial statements have been prepared on an accrual basis of accounting, in accordance with accounting principles generally accepted in the United States of America (GAAP).

In preparing the accompanying consolidated financial statements, the Company has reviewed, as determined necessary by the Company s management, events that have occurred after December 31, 2009, up until the issuance of the financial statements, which occurred on February 24, 2010.

Note 2 Significant Accounting Policies and Related Matters

Asset retirement obligations (AROs). AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset s acquisition, construction, development and/or normal operation. The Company s AROs are based on the estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and gas properties. An ARO is initially measured at its estimated fair value. Upon initial recognition, the Company records an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. The cost of the long-lived asset (including the ARO-related increase) is depreciated using a systematic and rational allocation method over the period during which the long-lived asset is expected to provide benefits. After the initial period of ARO recognition, the ARO will change as a result of either the passage of time or revisions to the original estimates of either the amounts of estimated cash flows or their timing. Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Upon settlement, AROs will be extinguished by the Company at either the recorded amount or the Company will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost.

Cash and Cash Equivalents. Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. The Company considers cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value. As of December 31, 2009, accounts payable included $3.6 million of outstanding checks that were reclassified from cash and cash equivalents.

Comprehensive Income. Comprehensive income includes net income and other comprehensive income, which includes unrealized gains and losses on derivative instruments that are designated as cash flow hedges.

Concentration of Credit Risk. Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of trade accounts receivable and commodity derivative instruments.

The Company extends credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within the Company s industry and may accordingly impact its overall credit risk. The Company believes that the risk of these unsecured receivables is mitigated by the size, reputation and nature of the companies to which the Company extends credit.

During the year ended December 31, 2009, transactions with Shell Trading, Chevron Corporation and BG Energy Merchants, LLC represented 39%, 23% and 19% of the Company and the Predecessor s combined oil and gas revenues.

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts, based on the specific identification method. In evaluating the collectability of accounts receivable, the Company makes judgments regarding each party s ability to make required payments, economic events and other factors. As the financial condition of any party changes, circumstances develop or additional information becomes available, adjustments to an allowance for doubtful accounts may be required. The Company did not have an allowance for doubtful accounts as of December 31, 2009.

The Company uses crude oil and natural gas derivative instruments to mitigate the effects of commodity price fluctuations and these derivative instruments expose the Company to counterparty credit risk. The Company s counterparties are generally major banks or financial institutions. All derivative instruments are executed under master agreements which allow the Company, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If the Company chooses to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election. The Company monitors the creditworthiness of its counterparties. However, the Company is not able to predict sudden changes in a counterparty s creditworthiness. Should a financial counterparty not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices as well as incur a loss.

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As of December 31, 2009, an affiliate of The Royal Bank of Scotland (RBS) accounted for 100% of the Company s counterparty credit exposure related to commodity derivative instruments. RBS is a major financial institution possessing an investment grade credit rating, based upon minimum credit ratings assigned by Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc.

Consolidation Policy. The Company s consolidated financial statements include the accounts of the Company and of its wholly-owned subsidiaries, after the elimination of all material intercompany accounts and transactions.

Contingencies. Certain conditions may exist as of the date the Company s consolidated financial statements are issued, which may result in a loss to the Company but which will only be resolved when one or more future events occur or fail to occur. The Company s management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment.

In assessing loss contingencies related to legal proceedings that are pending against the Company or unasserted claims that may result in proceedings, the Company s management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein. If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in the Company s consolidated financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss (if determinable and material), is disclosed.

Liabilities for environmental remediation costs arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Debt Issue Costs. Costs incurred in connection with the issuance of long-term debt are capitalized and charged to interest expense over the term of the related debt.

Income Taxes. The Company is not subject to income taxes. As a result, the Company s earnings or losses for income tax purposes are included in the tax returns of its members.

Natural Gas Imbalances. Quantities of natural gas over-delivered or under-delivered related to operational balancing agreements are recorded monthly as receivables and payables using weighted average prices as of the time the imbalance was created. Monthly, inventory imbalances receivable are valued at the lower of cost or market; inventory imbalances payable are valued at replacement cost. Certain contracts require cash settlement of imbalances on a current basis. Under these contracts, imbalance cash-outs are recorded as a sale or purchase of natural gas, as appropriate.

Price Risk Management (Hedging). All derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If a derivative qualifies for hedge accounting and is designated as a cash flow hedge, the effective portion of the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income (AOCI), a component of members equity, and reclassified to earnings when the forecasted transaction occurs. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

During 2008, the Predecessor voluntarily discontinued cash flow hedge accounting on all existing derivative instruments. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is no longer probable that a hedged forecasted transaction will occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

Property and Equipment. The Company uses the successful efforts method to account for its crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related ARO assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized. Costs also are capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience, and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease-by-lease basis if unsuccessful or the lease term has expired. All other exploratory wells and costs are expensed.

Long-lived assets to be held and used, including proved crude oil and natural gas properties, are assessed for possible impairment by comparing their carrying values with their associated undiscounted future net cash flows. Events that can trigger assessments for possible impairments include write-downs of proved reserves based on field performance, significant decreases in the market value of an asset, significant change in the extent or manner of use of or a physical change in an asset, significant change in the relationship between an asset s capitalized cost and proved reserves, and a more-likely-than-not expectation that a long-lived asset will be sold or otherwise disposed of significantly sooner than the end of its previously estimated useful life. Impaired assets are written down to their estimated fair values, generally their discounted future net cash flows. For proved crude oil and natural gas properties, the Company performs the impairment review on an individual field basis. Impairment amounts are recorded as incremental Depreciation, depletion and amortization expense.

In determining the fair values of proved and unproved properties acquired in business combinations, the Company prepares estimates of crude oil and natural gas reserves. The Company estimates future prices to apply to the estimated reserve quantities acquired, and estimates future operating and development costs, to arrive at estimates of future net cash flows. For the fair value assigned to proved, probable and possible reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate deemed appropriate at the time of the business combination. To compensate for the inherent risk of estimating and valuing reserves, the discounted future net cash flows of proved, probable and possible reserves are reduced by additional risk-weighting factors.

Other property and equipment items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets.

Revenue Recognition. The Company records revenues from the sales of crude oil, natural gas and NGLs when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured.

When the Company has an interest with other producers in properties from which natural gas is produced, the Company uses the entitlement method to account for any imbalances. Imbalances occur when the Company sells more or less product than the Company is entitled to under its ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that the Company sells in excess of its entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount the Company sells is recognized as revenue and a receivable is accrued.

Segment Information. The Company acquires, exploits, develops, explores for and produces crude oil and natural gas and all of the Company s operations are located in the United States. The Company s management team administers all properties as a whole rather than as discrete operating segments. The Company tracks basic operational data by area. However, the Company measures financial performance as a single enterprise and not on an area-by-area basis. The Company allocates capital resources on a project-by-project basis across its entire asset base to maximize profitability without regard to individual areas or segments.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the period. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating crude oil and natural gas reserves, (2) estimating uncollected revenues and operating and general and administrative costs, (3) developing fair value assumptions, including estimates of future cash flows and discount rates, (4) analyzing long-lived assets for possible impairment, (5) estimating the useful lives of assets and (6) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from estimated amounts.

Recent Accounting Pronouncements

In June 2009, the Financial Accounting Standards Board (FASB) established the FASB Accounting Standards Codification (Codification , or ASC) as the source of authoritative GAAP for U.S. companies. The ASC reorganized GAAP into a topical format and significantly changes the way users research accounting issues. For SEC registrants, the rules and interpretive releases of the SEC under federal securities laws are also sources of authoritative GAAP. References to specific GAAP in the Company s consolidated financial statements now refer exclusively to the ASC. The Company adopted the codification on December 31, 2009.

Business Combinations

In December 2007, FASB issued new guidance on business combinations. The new standard provides revised guidance on how acquirors recognize and measure the consideration transferred, identifiable assets acquired, liabilities assumed, noncontrolling interests, and goodwill acquired in a business combination. The new standard also expands required disclosures surrounding the nature and financial effects of business combinations. The standard is effective, on a prospective basis, for fiscal years beginning after December 15, 2008. Upon adoption, this standard did not have a material impact on the Company s consolidated financial position and results of operations. However, the standard did impact the Company s accounting for its acquisition of Bandon. See Note 4.

In April 2009, FASB issued new guidance on business combinations to amend and clarify application issues associated with initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. The guidance is effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The implementation of this standard did not have a material impact on the Company s consolidated financial position and results of operations.

Fair Value Measurements

In February 2008, FASB issued authoritative guidance deferring the effective date of the fair value guidance for all nonfinancial assets and nonfinancial liabilities to fiscal years beginning after November 15, 2008. The implementation of the fair value guidance for nonfinancial assets and nonfinancial liabilities, effective January 1, 2009, did not have a material impact on the Company s consolidated financial position and results of operations. See Note 9 for additional fair value information and disclosure for financial and nonfinancial assets and liabilities.

In September 2009, FASB issued additional guidance on measuring the fair value of liabilities effective for the first reporting period beginning after issuance. Implementation is not expected to have a material impact on the Company s consolidated financial position and results of operations.

Oil and Gas Reserve Estimation and Disclosure

In January 2010, FASB issued authoritative guidance on extractive activities for oil and gas reserve estimation and disclosures. The new guidance, among other purposes, is primarily intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves by expanding the definition of proved oil and gas producing activities, requiring disclosure of geographical areas that represent a certain percentage of proved reserves, updating the reserve estimation requirements for changes in practice and technology that have occurred over the past several decades, amending the definition of proved oil and gas reserves to change the pricing used in estimating reserves to the simple arithmetic average of the prices posted on the first day of each month in the entity s fiscal year and requiring that an entity continue to disclose separately the amounts and quantities for consolidated and equity method investments. The Company s results for the period from October 13 through December 31, 2009 were based upon proved reserves that were determined using the new reserve guidelines, whereas the predecessor period results were based on the prior methodology.

Other

In May 2009, FASB issued new guidance on subsequent events, particularly with respect to management s assessment of subsequent events. The guidance is effective prospectively for interim and annual periods ending after June 15, 2009. The implementation of this standard did not have a material impact on the Company s consolidated financial position and results of operations. See Note 1.

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Note 3 Consolidated Financial Statements Information

Additional consolidated balance sheet information as of December 31, 2009 is as follows:

Accounts receivable	
Oil and gas revenues	$ 12,410
Other	1,146
	$ 13,556
Other current assets	
Prepaid insurance	$ 5,706
Prepaid royalties	1,523
Advances to operators	593
Other	109
	$ 7,931
Other assets	
Natural gas imbalance receivable (1,640 MMcf)	$ 6,746
Debt issue costs	199
	$ 6,945
Other long-term liabilities	
Natural gas imbalance payable (1,246 MMcf)	$ 5,142
Other	350
	$ 5,492

Additional consolidated statement of operations information is as follows:

	DBH, LLC October 13 through December 31, 2009	Predecessor January 1 through October 12, 2009
Other operating expenses		
Insurance expense	$ 2,424	$ 8,652
Workover expense	1,898	2,663
Accretion expense	950	4,496
Other (income) expense, net	(40)	2,726
	$ 5,232	$ 18,537

Note 4 Acquisition of Bandon

On October 13, 2009, in a series of transactions, the Company acquired Bandon. A summary of the transactions follows:

- the Company issued a member interest with a fair value of $5.3 million to acquire a loan receivable from Bandon with a face value of $119.5 million; and

- in a nonmonetary exchange with the owners of the Predecessor, the Company exchanged the loan receivable for a 100% ownership interest in Bandon.

The Company is a majority-owned subsidiary of Dynamic Offshore Resources, LLC (Dynamic). The Bandon acquisition substantially increases Dynamic s presence in the Gulf of Mexico. In addition to a substantial

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proved reserve base, management believes the Bandon assets offer significant upside potential attributable to several high impact prospects.

The acquisition was accounted for using the acquisition method and Bandon s results of operations were included in the Company s consolidated statement of operations effective October 13, 2009.

Certain of Bandon s property and equipment sustained damage during 2008 from the effects of Hurricanes Gustav and Ike. The Company s preliminary purchase price allocation reflects the Company s estimate of the amount expected to be recovered from property damage insurance claims.

The acquisition date fair values of the assets acquired, liabilities assumed and the purchase price are shown below:

Assets acquired:	
Cash	$ 40,524
Hurricane insurance receivable	30,008
Other current assets	41,329
Property and equipment	310,038
Other noncurrent assets	7,442
	429,341
Purchase price plus liabilities assumed:	
Purchase price	(5,294)
Asset retirement obligation, current portion	(27,152)
Other current liabilities	(23,632)
Long-term debt	(151,224)
Asset retirement obligation, noncurrent portion	(55,726)
Other noncurrent liabilities	(5,436)
	(268,464)
Bargain purchase gain	$ 160,877

The Company s estimate of the net assets fair value exceeded the estimated fair value of the total consideration paid which management believes resulted from the Predecessor s financial difficulties.

Unaudited Pro Forma Information

The following unaudited pro forma information shows the pro forma effect of the Bandon acquisition, assuming the transaction occurred on January 1, 2009. The Company believes the assumptions used provide a reasonable basis for presenting the pro forma significant effects directly attributable to the acquisition. This pro forma financial information does not purport to represent what the Company s results of operations would have been if the transaction had occurred on such date.

Revenues	$117,038
Loss from operations	978
Net income	15,829

Note 5 Property and Equipment

The components of property and equipment as of December 31, 2009 were as follows:

Proved oil and gas properties	$ 221,122
Unproved oil and gas properties	
Probable reserves	59,000
Possible reserves	30,000
Primary term leases	1,343
	311,465
Accumulated depreciation, depletion and amortization	(8,510)
	$ 302,955

During the period from January 1 through October 12, 2009, the Predecessor recognized a $9.1 million impairment charge related to its proved oil and gas properties. The impairment charge is included in the consolidated statement of operations as incremental depreciation, depletion and amortization expense.

Note 6 Asset Retirement Obligations

The following table summarizes the activity for the Company and the Predecessor s asset retirement obligations for the periods indicated:

	DBH, LLC October 13 through December 31, 2009	Predecessor January 1 through October 12, 2009
Beginning of period	$	$ 90,084
Liabilities acquired	82,878	
Liabilities settled	(8,039)	(641)
Accretion expense	950	4,496
Revisions to previous estimates		1,708
End of period	$ 75,789	$ 95,647

Note 7 Long-Term Debt

The Company had the following debt outstanding as of December 31, 2009:

Second Lien Term Loan, variable rate, due October 2014	$ 105,000
Revolving Credit Agreement, variable rate, due October 2012	
	$ 105,000
Letters of credit issued	$

Second Lien Amended and Restated Credit Agreement

On July 14, 2006, the Predecessor, Credit Suisse Securities, LLC and Banc of America Securities, LLC entered into a First Lien Credit Agreement. On October 13, 2009, Bandon entered into a Second Lien Amended and Restated Credit Agreement (the Second Lien Agreement). Under the Second Lien Agreement, amounts

outstanding under the First Lien Credit Agreement were converted into $151.2 million in term loans under the Second Lien Agreement.

Amounts outstanding under the Second Lien Agreement bear interest at the London Interbank Offered Rate (LIBOR) plus 5.0%. Accrued interest is payable on the last business day of each calendar quarter, commencing on December 31, 2009 and ending on October 13, 2014 (the maturity date), as well as each time Bandon makes a repayment or prepayment under the Second Lien Agreement.

Bandon was required to make mandatory prepayments as follows: (i) $26.2 million on October 13, 2009; and (ii) $20.0 million within 180 days of October 13, 2009. Both payments were made prior to December 31, 2009. In addition, under certain circumstances, Bandon is required to make prepayments with the proceeds of asset dispositions.

The Second Lien Agreement contains customary events of default and requires Bandon to satisfy various financial covenants, as defined in the Second Lien Agreement, including: (i) maintain a Total Leverage Ratio of less than 4.0 to 1.0 and an Interest Coverage Ratio of at least 2.5 to 1.0, beginning with the fiscal quarter ending September 30, 2011; and (ii) maintain a current ratio as of the end of each calendar quarter of at least 1.0 to 1.0.

The Second Lien Agreement also limits Bandon s ability to pay dividends or make other distributions, make acquisitions, make changes in its capital structure, create liens, and incur additional indebtedness. The Second Lien Agreement also requires Bandon to enter into commodity price hedging agreements for at least half of its estimated oil and gas production from proved developed producing reserves.

Revolving Credit Agreement

On October 13, 2009, Bandon entered into a revolving credit facility to provide for a three-year $25.0 million revolving credit facility (the Revolver). The initial borrowing base under the Revolver was $10.0 million with initial availability of $4.0 million. The full amount available under the Revolver is also available for the issuance of letters of credit.

The Revolver is subject to semiannual borrowing base redeterminations on April 1 and October 1 of each year. In addition to the scheduled semiannual borrowing base redetermination, the lenders or Bandon have the right to redetermine the borrowing base at any time, provided that no party can request more than one such redetermination between the regularly scheduled borrowing base redeterminations. The determination of Bandon s borrowing base is subject to a number of factors, including the quantities of proved oil and natural gas reserves, the lenders price assumptions and other various factors, some of which may be out of Bandon s control. Bandon s lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that the Company s crude oil and natural gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect. In this case, Bandon would be required to make three monthly payments each equal to one third of the amount by which the aggregate outstanding loans and letters of credit exceed the borrowing base.

Obligations under the Revolver are secured by first priority liens on substantially all of Bandon s assets. The Revolver also contains other restrictive covenants, including, among other items, maintenance of a leverage ratio, an interest coverage ratio, a current ratio (all as defined in the Revolver), restrictions on cash dividends, and restrictions on incurring additional indebtedness.

Under the Revolver, outstanding balances bear interest at either the alternate base rate plus a margin (based on a sliding scale of 1.50% to 2.25% based upon borrowing base usage) or LIBOR plus a margin (based on a sliding scale of 2.50% to 3.25%, based upon borrowing base usage). The alternate base rate is equal to the higher of (i) the Royal Bank of Scotland plc s prime rate; (ii) the federal funds rate plus 0.50%; or (iii) LIBOR plus

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1.00%. The Revolver also provides for commitment fees of 0.50% calculated on the difference between the borrowing base and the aggregate outstanding loans and letters of credit under the Revolver.

Note 8 Price Risk Management Activities

The Company s principal market risks are its exposure to changes in commodity prices, particularly to the prices of crude oil and natural gas, changes in interest rates, as well as nonperformance by the Company s counterparties.

Commodity Price Risk. The Company s revenues are derived principally from the sale of crude oil and natural gas. The prices of crude oil and natural gas are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond the Company s control. The Company monitors these risks and enters into commodity derivative transactions designed to mitigate the impact of commodity price fluctuations on the Company s business.

The primary purpose of the Company s commodity risk management activities is to hedge the Company s exposure to commodity price risk and reduce fluctuations in the Company s operating cash flow despite fluctuations in commodity prices. As of December 31, 2009, the Company has hedged the commodity price associated with a significant portion of its expected crude oil and natural gas sales volumes for the years 2010 through 2012 by entering into derivative financial instruments comprising swaps. The percentages of the Company s expected crude oil and natural gas that are hedged decrease over time. With swaps, the Company typically receives an agreed upon fixed price for a specified notional quantity of crude oil or natural gas and the Company pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Company receives from its crude oil and natural gas marketing counterparties a price based on the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than the Company s actual equity volumes, the Company typically limits its use of swaps to hedge the prices of less than the Company s expected crude oil and natural gas sales volumes. The Company may utilize purchased puts (or floors) to hedge additional expected commodity volumes without creating volumetric risk. The Company s commodity hedges may expose the Company to the risk of financial loss in certain circumstances. The Company s hedging arrangements provide the Company protection on the hedged volumes if market prices decline below the prices at which these hedges are set. If market prices rise above the prices at which the Company has hedged, the Company will receive less revenue on the hedged volumes than in the absence of hedges.

Interest Rate Risk. The Company is exposed to changes in interest rates, primarily as a result of variable rate borrowings under its debt agreements. To the extent that interest rates increase, interest expense for the Company s variable rate debt will also increase. As of December 31, 2009, the Company had borrowings of $105 million outstanding under its variable rate debt agreements. In an effort to reduce the variability of its cash flows, the Company may enter into interest rate swap and interest rate basis swap agreements. Under these agreements, the base interest rate on the specified notional amount of the Company s variable rate debt is effectively fixed for the term of each agreement.

Credit Risk. The Company s credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value to the Company at the reporting date. At such times, these outstanding instruments expose the Company to credit loss in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of the Company s counterparties decline, the Company s ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, the Company may sustain a loss and the Company s cash receipts could be negatively impacted.

As of December 31, 2009, an affiliate of RBS accounted for 100% of the Company s counterparty credit exposure related to commodity derivative instruments. RBS is a major financial institution possessing an investment grade credit rating, based upon minimum credit ratings assigned by Standard & Poor s Ratings Services, a division of the McGraw-Hill Companies, Inc.

The Company had the following commodity derivatives outstanding as of December 31, 2009, none of which have been designated as cash flow hedges:

Crude Oil

Instrument Type	Index	Avg. Price $/Bbl	Barrels 2010	Barrels 2011	Barrels 2012	Fair Value
Swap	CL-NYM	$ 78.00	240,000			$ (885)
Swap	CL-NYM	78.00		106,000		(820)
			240,000	106,000		$ (1,705)

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu 2010	MMBtu 2011	MMBtu 2012	Fair Value
Swap	NG-NYM	$ 6.31	4,545,000			$ 2,648
Swap	NG-NYM	6.31		2,205,000		(89)
Swap	NG-NYM	6.31			1,340,000	(236)
			4,545,000	2,205,000	1,340,000	$ 2,323

The following reflects the fair values of derivative instruments in the Company s consolidated balance sheet as of December 31, 2009:

Derivatives not designated as hedging instruments under ASC 815	**Asset Derivatives** Balance Sheet Location	**Asset Derivatives** Fair Value	**Liability Derivatives** Balance Sheet Location	**Liability Derivatives** Fair Value
Commodity derivatives	Current assets	$1,763	Long-term liabilities	$1,145

The following reflects the effective portion of amounts reclassified from AOCI to revenue and expense for the periods indicated:

Location of Gain (Loss) Reclassified from AOCI into Income	**DBH, LLC October 13 through December 31, 2009**	**Predecessor January 1 through October 12, 2009**
Oil and gas revenues	$	$ 11,618
Interest expense, net		(1,487)

$	$	10,131

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Note 9 Fair Value Measurements

Accounting standards pertaining to fair value measurements establish a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include:

Level 1, defined as observable inputs such as quoted prices in active markets;

Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and

Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Company s commodity derivative contracts are reported in its consolidated financial statements at fair value. These contracts consist of over-the-counter (OTC) swap contracts, which are not traded on a public exchange.

The fair values of swap contracts are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Therefore, the Company has categorized these swap contracts as Level 2.

The Company has consistently applied these valuation techniques and believes it has obtained the most accurate information available for the types of derivative contracts it holds.

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2009. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$1,763	$	$1,763	$
Liabilities from commodity derivative contracts	$1,145	$	$1,145	$

The following table sets forth a reconciliation of the changes in the fair value of the Company s financial instruments classified as Level 3 in the fair value hierarchy:

	DBH, LLC October 13 through December 31, 2009	Predecessor January 1 through October 12, 2009
Balance, beginning of period	$	$ (1,940)
Change in fair value of interest rate derivative instruments		451
Settlements		1,489
Balance, end of period	$	$

The Company s nonfinancial assets and liabilities measured at fair value on a nonrecurring basis during the year ended December 31, 2009 were not significant.

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Note 10 Members Equity

The Company has two classes of members equity (Classes A and B). Generally, income, losses and distributions are allocated to all members in proportion to their percentage interest held, regardless of class. Membership interests are restricted securities under federal and state securities laws and will not be transferable unless certain conditions imposed by those laws and the Company s limited liability company agreement are met.

All classes of members equity have similar voting rights other than for appointing the Board of Managers to represent their respective classes. Initially, the Board of Managers is represented by four Class A members. At all times while the Class B members hold at least 8% of the aggregate members equity, they have the right to appoint one Class B manager to the Board of Managers.

The Board of Managers has the right to approve: (i) the sale of all or substantially all of the assets of the Company, (ii) a merger or consolidation of the Company, or (iii) dissolution of the Company (collectively, a Sale). During the three year period ending October 13, 2012, in conjunction with a Sale, the Company may elect to purchase the Class B members interest for $50.0 million.

Note 11 Related Party Transactions

DBH, LLC

Relationship with Dynamic

The employees supporting the Company s operations are employees of an affiliate of Dynamic. The Company s consolidated statement of operations for the period from October 13 through December 31, 2009 includes costs allocated to them for centralized general and administrative services performed by Dynamic, as well as direct costs for field employees and certain transportation services provided through a Dynamic subsidiary. Costs allocated to the Company were based on identification of Dynamic s resources that directly benefit the Company and its proportionate share of costs based on the Company s estimated usage of shared resources and functions. All of the allocations are based on assumptions that management believes are reasonable; however, these allocations are not necessarily indicative of the costs and expenses that would have resulted if the Company had been operated as a stand-alone entity. These allocations, which are settled in cash monthly, were as follows:

Allocated general and administrative expense	$ 1,800
Field employee payroll expense	128
Transportation services	156
	$ 2,084

Relationship with SESI

The Company has entered into a preferred provider agreement with SESI, a provider of services to oil and gas companies. Under the terms of the agreement, the Company is to award work for field-level services to SESI, provided the cost is competitive with third party estimates for similar services. During the period from October 13 through December 31, 2009, SESI provided $2.4 million in field-level services to the Company. As of December 31, 2009, accounts payable to SESI were $0.7 million.

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Predecessor

The Predecessor had an operating services agreement with BR and SESI. Under the agreement, BR and SESI were reimbursed for all direct and indirect costs incurred with respect to operational and accounting services provided to the Predecessor. During the period from January 1 through October 12, 2009, BR charged the Predecessor $7.0 million in general and administrative expenses and SESI provided $10.3 million in field-level services

Note 12 Commitments and Contingencies

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

The Company holds a lease for the Predecessor s previous office space in Houston, Texas. The annual rental commitment is $0.4 million and escalates each year. During 2009, the Company and Predecessor incurred rent expense of $0.3 million.

Noncancellable commitments under the lease are $0.4 million for each of the years ending December 31, 2010 and 2011; and $0.3 million for the year ending December 31, 2012.

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Supplemental Oil and Gas Disclosures
(Unaudited)

The supplemental data presented herein reflects information for the Company s crude oil and natural gas producing activities, all of which are in the United States of America.

Oil and Gas Reserves

The Company s estimates of proved reserves as of December 31, 2009 are based on reserve reports prepared by independent petroleum engineers. Users of this information should be aware that the process of estimating quantities of proved and proved-developed crude oil and natural gas reserves is very complex, requiring significant subjective decision making in the analysis and evaluation of all geological, engineering, and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including additional development activity, additional production data, evolving production history, and continual reassessment of the viability of production under different economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates 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 oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed oil and gas reserves are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

In January 2010 FASB issued Accounting Standards Update 2010-03, *Oil and Gas Reserve Estimation and Disclosure.* See Note 2. Application of the new rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have resulted under the previous rules. Use of 12-month average pricing at December 31, 2009 as required by the new rules resulted in a decrease in proved reserves of 145.9 MBbl and 5,057.2 MMcf. The following table sets forth the Company s net proved reserves, including changes therein (including changes during the predecessor period), and proved developed reserves:

	Crude oil (MBbl)	**Natural gas (MMcf)**
December 31, 2008	3,920	76,803
Purchases of reserves in place		
Extensions and discoveries	39	540
Revisions of prior estimates	583	(965)
Production	(835)	(12,479)
December 31, 2009	3,707	63,899
Proved-developed reserves:		
December 31, 2008	3,385	66,752
December 31, 2009	3,297	57,295

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Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities

Costs incurred, on an accrual basis, represent amounts capitalized or expensed during 2009 by the Company and the Predecessor for property acquisition, exploration, and development activities. Costs incurred for property acquisitions, exploration, and development activities were as follows (in thousands):

Acquisition of properties proved	$
Acquisition of properties unproved	
Total acquisition costs incurred	$
Exploration costs	2,489
Development costs	32,852
Total costs incurred	$ 35,341

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The following information has been developed utilizing procedures prescribed by ASC 932. 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 (Standardized Measure) 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:

Future costs and selling prices will probably differ from those required to be used in these calculations.

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.

Selection of a 10% discount rate is required by ASC 932 and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues.

Under the Standardized Measure, future cash inflows were estimated by applying the 12-month simple arithmetic average of the first-day-of-the-month price for the period January through December 2009 for oil and natural gas prices adjusted for price 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. Use of a 10% discount rate is required by ASC 932. No income tax estimates are incorporated, as the Company does not pay income taxes.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows for the year ended December 31, 2009:

Future cash inflows	$ 447,505
Future production costs	(127,437)
Future development and abandonment costs	(141,077)
Future net cash flows	178,991
10% annual discount for estimated timing of cash flows	(31,181)
Standardized measure of discounted future net cash flows	$ 147,810

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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 year ended December 31, 2009 is as follows:

Beginning of year	$ 198,321
Sales and transfers of oil and natural gas produced, net of production costs	(59,297)
Net changes in prices and production costs	(81,632)
Net changes in estimated future development costs	21,275
Extensions and discoveries	2,375
Revisions of quantity estimates	7,760
Development costs incurred	32,852
Purchase and sales of reserves in place	
Changes in production rates (timing) and other	9,184
Accretion of discount	16,972
Net decrease	(50,511)
End of year	$ 147,810

The discounted future net cash flows as of December 31, 2009 were estimated by independent petroleum engineers using the 12-month simple arithmetic average of the first-day-of-the-month price for the period January through December 2009 for light sweet crude oil of $61.04 per bbl, and a Henry Hub natural gas price of $3.86 per MMBtu, and price differentials provided by the Company.

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BERYL OIL AND GAS LP
Balance Sheets
Unaudited
December 31, 2008 and 2007
(in thousands)

	2008	2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 80,881	$ 72,364
Accounts receivable, net of allowance of $500 and $0	24,026	45,750
Prepaid expenses and other	4,664	2,551
Fair value of derivative instruments	33,648	9,478
Total current assets	143,219	130,143
Property and equipment:		
Oil and gas properties, at cost (successful efforts method)	679,270	615,506
Other equipment	2,794	2,627
Less accumulated depreciation, depletion, and amortization	(239,189)	(162,265)
Property and equipment, net	442,875	455,868
Fair value of derivative instruments	6,508	
Deferred financing costs, net of accumulated amortization of $6,161 and $2,955	4,189	7,395
Total assets	$ 596,791	$ 593,406
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 59,622	$ 33,324
Accounts payable to affiliates	1,852	2,838
Accrued interest	959	1,593
Fair value of derivative instruments	1,940	8,934
Asset retirement obligations	14,785	2,811
Current maturities of long-term debt	26,223	24,246
Total current liabilities	105,381	73,746
Fair value of derivative instruments		6,091
Asset retirement obligations	75,299	76,803
Long-term debt, net of unamortized loan discount of $1,385 and $1,905	271,207	296,908
Partners capital	131,174	150,204

Accumulated other comprehensive income (loss)	13,730	(10,346)
Total partners capital	144,904	139,858
Commitments and contingencies (note 12)		
Total liabilities and partners capital	$ 596,791	$ 593,406

See accompanying notes to financial statements.

BERYL OIL AND GAS LP
Statements of Operations
Unaudited
Years ended December 31, 2008 and 2007
(in thousands)

	2008	2007
Operating revenues:		
Oil revenue	$ 79,367	$ 87,767
Gas revenue	106,476	136,230
Total operating revenues	185,843	223,997
Operating expenses:		
Lease operating expenses	47,789	37,833
Insurance expense	9,517	14,246
Transportation expense	1,445	891
Exploration expense	2,802	4,873
Depreciation, depletion, and amortization	76,924	104,250
Impairment and dry hole expense	34,878	7,881
Accretion expense	5,035	5,816
(Gain) loss on plugging and abandonment	2,491	(101)
Loss on sale of property and equipment		(1,930)
General and administrative expenses	12,296	15,098
Total operating expenses	193,177	188,857
Other income (expenses):		
Interest expense	(31,158)	(41,246)
Interest income	2,032	4,140
Loss on early extinguishment of debt		(708)
Derivative instruments	17,430	(5,968)
Total other expenses	(11,696)	(43,782)
Net loss	$ (19,030)	$ (8,642)

See accompanying notes to financial statements.

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BERYL OIL AND GAS LP

Statements of Partners Capital

Unaudited

Years ended December 31, 2008 and 2007

(in thousands)

	Superior Energy Services, Inc	Beryl Resources LP	Total
Balance at December 31, 2006	$ 69,083	$ 103,625	$ 172,708
Comprehensive loss:			
Net loss	(3,457)	(5,185)	(8,642)
Unrealized loss on derivative instruments	(9,683)	(14,525)	(24,208)
Total comprehensive loss	(13,140)	(19,710)	(32,850)
Balance at December 31, 2007	55,943	83,915	139,858
Comprehensive (loss) income:			
Net loss	(7,612)	(11,418)	(19,030)
Unrealized gain on derivative instruments	9,631	14,445	24,076
Total comprehensive income	2,019	3,027	5,046
Balance at December 31, 2008	$ 57,962	$ 86,942	$ 144,904

See accompanying notes to financial statements.

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BERYL OIL AND GAS LP

Statements of Cash Flows

Unaudited

Years ended December 31, 2008 and 2007

(in thousands)

	2008	2007
Cash flows from operating activities:		
Net loss	$ (19,030)	$ (8,642)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, and amortization	76,924	104,250
Impairment and dry hole expense	34,878	7,881
Accretion expense	5,035	5,816
Unrealized (gain) loss on derivative instruments	(15,663)	23,729
Amortization of deferred financing costs and discount	3,727	1,981
Gain on sale of property and equipment		(1,930)
Loss on extinguishment of debt		708
(Gain) loss on plugging and abandonment	2,491	(101)
Changes in assets and liabilities:		
Accounts receivable	19,295	(6,642)
Prepaid expenses and other	(6,138)	10,378
Accounts payable and accrued liabilities	(1,064)	(1,345)
Accounts payable to affiliates	(986)	(28)
Accrued interest	(634)	(567)
Settlements of asset retirement obligation	(1,656)	
Net cash provided by operating activities	97,179	135,488
Cash flows from investing activities:		
Acquisitions of oil and gas properties	(1,653)	(389)
Additions to oil and gas properties	(62,596)	(44,091)
Additions to equipment	(167)	(2,141)
Net cash used in investing activities	(64,416)	(46,621)
Cash flows from financing activity:		
Repayment of long-term debt	(24,246)	(111,940)
Net cash used in financing activity	(24,246)	(111,940)
Net change in cash and cash equivalents	8,517	(23,073)
Cash and cash equivalents, beginning of year	72,364	95,437
Cash and cash equivalents, end of year	$ 80,881	$ 72,364
Supplemental cash flow disclosure:		
Cash paid for interest	$ 25,538	$ 39,295

See accompanying notes to financial statements.

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BERYL OIL AND GAS LP
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(1) Organization and Summary of Significant Accounting Policies

(a) Organization and Nature of Business

Beryl Oil and Gas LP (the Partnership), which changed its name from Coldren Resources LP in May 2007, is a Delaware limited partnership that was organized in May 2006 for the purpose of acquiring offshore oil and gas properties. The Partnership is a joint venture between Beryl Resources LP (BR), formerly named Coldren Oil and Gas Company LP, and Superior Energy Services, Inc. (SESI). BR owns 60% of the Partnership and acts as the managing partner, while SESI owns 40%. The Partnership has no employees and all business activity was managed by BR or SESI personnel during 2008 and 2007.

(b) Basis of Presentation

The accompanying financial statements have been prepared on an accrual basis of accounting, in accordance with accounting principles generally accepted in the United States of America.

(c) Cash Equivalents

The Partnership considers all highly liquid investments with an original maturity of three months or less when purchased to be cash equivalents. Cash equivalents are stated at cost, which approximates market value.

(d) Accounts Receivable and Allowances

Trade accounts receivables are recorded at the invoiced amount and do not bear interest. The Partnership determines the allowances based on historical write-off experience and specific identification. As of December 31, 2008, the Partnership had $0.5 million of allowances for doubtful accounts. There were no such allowances for doubtful accounts as of December 31, 2007.

(e) Property and Equipment

Proved Oil and Properties

The Partnership accounts for oil and gas properties under the successful efforts method. Under this method, all leasehold and development cost of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of proved reserves and proved developed reserves, respectively.

The Partnership evaluates the impairment of its proved oil and gas properties on a depletable unit basis whenever events or changes in circumstances indicate an asset s carrying amount may not be recoverable. The carrying amount of proved oil and gas properties, is reduced to fair value when the expected undiscounted future cash flows are less than the assets net book value. Cash flows are determined based upon reserves using prices, costs, and discount factors consistent with those used for internal decision making. Costs of retired, sold, or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion, and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other

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properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred as part of lease operating expenses. Estimated dismantlement and abandonment costs for oil and gas properties are capitalized at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved Oil and Gas Properties

Unproved properties consist of costs incurred to acquire unproved leasehold as well as costs to acquire unproved resources. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience, and average lease-term lives. Individually significant leases are reclassified to proved properties if successful and expensed on a lease-by-lease basis if unsuccessful or the lease term has expired. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The carrying value of the Partnership s unproved resources, acquired in connection with business acquisitions, was determined using the market-based weighted average cost of capital rate, subjected to additional project-specific risk factors. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. As the unproved resources are developed and proved, the associated costs are reclassified to proved properties and depleted on a unit-of-production basis. The Partnership assesses unproved resources for impairment annually on the basis of the experience of the Partnership in similar situations and other information about such factors as the primary lease terms of those properties, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past.

Impairment

Based on the analysis described above, the Partnership recorded an impairment of oil and gas properties of approximately $34.9 million for the year ended December 31, 2008, which is included in impairment and dry hole expense on the statement of operations. The Partnership recorded a noncash impairment of approximately $7.9 million of oil and gas properties for the year ended December 31, 2007.

Exploration Costs

Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration costs. The costs of any exploratory wells are carried as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as the Partnership is making sufficient progress towards assessing the reserves and the economic and operating viability of the project.

Other Property and Equipment

Other property and equipment, consisting primarily of office furniture, equipment, leasehold improvements, computers, and computer software, are stated at cost. Depreciation on property and

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equipment is calculated on the straight-line method over the estimated useful lives of the assets, which range from three to seven years.

(f) Asset Retirement Obligations

The Partnership accounts for its asset retirement obligations in accordance with Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires the Partnership to record the fair value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. The liability is capitalized as part of the related long-lived asset s carrying amount. Over time, accretion of the liability is recognized as an operating expense and the capitalized cost is depleted over the expected useful life of the related asset. The Partnership s asset retirement obligations relate primarily to the plugging, dismantlement, removal, site reclamation, and similar activities of its oil and gas properties.

(g) Financial Instruments

The fair value of the Partnership s financial instruments of cash, accounts receivable, and current maturities of long-term debt approximates their carrying amount. The carrying value of the Partnership s debt is approximately $298.8 million and $323.1 million at December 31, 2008 and 2007, respectively. The fair value of the Partnership s cash and cash equivalents is approximately $80.9 million and $72.4 million at December 31, 2008 and 2007, respectively.

(h) Revenue Recognition

The Partnership records revenues from the sale of its oil and gas production when the product is delivered at a determinable price, title has transferred, and collectibility is reasonably assured. When the Partnership has an interest with other producers in properties from which natural gas is produced, the Partnership uses the entitlement method for recording gas sales revenue. Under this method of accounting, revenue is recorded based on the Partnership s net revenue interest in field production. Deliveries of gas in excess of the Partnership s revenue interest are recorded as liabilities and underdeliveries are recorded as receivables. The Partnership also had gas imbalance receivables of $11.1 million and producer gas payables of $8.6 million at December 31, 2008. The Partnership had gas imbalance receivables of $7.1 million and producer gas payables of $5.6 million at December 31, 2007.

(i) Derivative Instruments and Hedging Activities

The Partnership accounts for derivative instruments and hedging activities in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended (SFAS No. 133). SFAS No. 133 established accounting and reporting standards requiring every derivative instrument (including certain derivative instruments embedded in other contracts) to be recorded on the balance sheet as either an asset or liability measured at fair value. SFAS No. 133 requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Under cash flow hedge accounting, gains and losses are reflected in partners capital as accumulated other comprehensive income or loss (AOCI) until the forecasted

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transaction occurs. The derivative s gains or losses are then offset against related results on the hedged transaction on the statement of operations. SFAS No. 133 also requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Only derivative instruments that are expected to be highly effective in offsetting anticipated gains or losses on the hedged cash flows and that are subsequently documented to have been highly effective can qualify for hedge accounting. Effectiveness must be assessed both at inception of the hedge and on an ongoing basis. Any ineffectiveness in hedging instruments whereby gains or losses do not exactly offset anticipated gains or losses of hedged cash flows is measured and recognized in earnings in the period in which it occurs. The Partnership assesses hedge effectiveness on an ongoing basis based on total changes in the derivative s fair value and using regression analysis. A hedge is considered effective if certain statistical tests are met. For derivatives not qualifying for hedge accounting, the changes in fair value are recorded as other income (expense) on the consolidated statements of operations.

Through October 31, 2008, the Partnership elected to designate the majority of its crude oil and natural gas derivative instruments as cash flow hedges. On November 1, 2008, the Partnership discontinued cash flow hedge accounting on all existing commodity derivative instruments. The Partnership voluntarily made this change to provide greater flexibility in its use of derivative instruments. From November 1, 2008 forward, the Partnership recognized all realized and unrealized gains and losses on such instruments in earnings in the period in which they occur. Net derivative losses that were deferred in AOCI as of October 31, 2008, will be reclassified to earnings in future periods as the original hedged transactions affect earnings. During 2008, the Partnership reclassified $1.9 million of derivative gains from other comprehensive income to net loss as it was probable that the original forecasted transaction would not occur by the end of the original period or an additional two-month time period. The discontinuance of cash flow hedge accounting for commodity derivative instruments did not affect the Partnership s net assets or cash flows at December 31, 2008 and does not require adjustments to previously reported financial statements.

(j) Income Taxes

The Partnership does not pay income taxes as profits or losses are reported directly to the taxing authorities by the individual partners. Accordingly, no provision for income taxes has been included in the accompanying financial statements.

(k) Deferred Financing Costs

Costs incurred to obtain debt financing are deferred and are amortized as additional interest expense over the maturity period of the related debt.

(l) Allocation of Income and Distributions to Partners

The partnership agreement allows for revenues and expenditures to be allocated between the general partner and limited partner in accordance with their respective sharing ratios.

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(m) Use of Estimates

The preparation of the 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 the reported amounts of revenues and expenses during the reporting period. The Partnership s most significant financial estimates are based on remaining proved oil and natural gas reserve volumes. Estimates of remaining proved reserve volumes are a key component in determining the Partnership s depletion rate for oil and gas properties. Estimation of the values of the Partnership s remaining proved reserves is a key component in determining the need for impairment of the oil and natural gas asset base. These estimates require assumptions regarding future commodity prices and future costs and expenses, as well as future production rates. Actual results could differ from these estimates.

(n) Recently Issued Accounting Standards

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115*. SFAS No. 159 gives the Partnership the irrevocable option to carry most financial assets and liabilities at fair value that are not currently required to be measured at fair value. If the fair value option is elected, changes in fair value would be recorded in earnings at each subsequent reporting date. SFAS No. 159 is effective for the Partnership s 2008 fiscal year. The adoption of this statement did not have a material impact on the Partnership s financial condition, results of operations, and cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 defines fair value, establishes a framework for the measurement of fair value, and enhances disclosures about fair value measurements. The statement does not require any new fair value measures. The statement is effective for fair value measures already required or permitted by other standards for fiscal years beginning after November 15, 2007. The Partnership was required to adopt SFAS No. 157 beginning on January 1, 2008. SFAS No. 157 is required to be applied prospectively, except for certain financial instruments. Any transition adjustment will be recognized as an adjustment to opening retained earnings in the year of adoption. In November 2007, the FASB proposed a one-year deferral of SFAS No. 157 s fair value measurement requirements for nonfinancial assets and liabilities that are not required or permitted to be measured at fair value on a recurring basis. The Partnership adopted SFAS No. 157 and the impact on its results of operations and financial position is approximately $0.4 million during 2008.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations,* and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment to ARB No. 51*. SFAS Nos. 141(R) and 160 require most identifiable assets, liabilities, noncontrolling interests, and goodwill acquired in a business combination to be recorded at full fair value and require noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity, which changes the accounting for transactions with noncontrolling interest holders. Both statements are effective for periods beginning on or after December 15, 2008, and earlier adoption is prohibited. SFAS No. 141(R) will be applied to business combinations occurring after the effective

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date. SFAS No. 160 will be applied prospectively to all noncontrolling interests, including any that arose before the effective date. The Partnership is currently evaluating the impact of adopting SFAS Nos. 141(R) and 160 on its results of operations and financial position.

(2) Significant Concentrations

For the years ended December 31, 2008 and 2007, the Partnership s oil and gas revenue (excluding the effects of hedging activities) was attributable to the following significant customers, as a percentage of total revenues:

	December 31,	
	2008	**2007**
Noble Energy	%	9%
Louis Dreyfus	19	17
W&T Offshore	24	14
Chevron	20	14
Shell Oil Company	24	11
Total	87%	65%

(3) Related-Party Transactions

The Partnership has an operating services agreement that covers services provided by BR and SESI. BR and SESI provide operational and accounting functions under the operating services agreement that provides for reimbursement of all direct and indirect costs incurred as part of the agreement. These management fees were paid to SESI and recorded by the Partnership as general and administrative expenses totaling $0.5 million and $4.1 million for the years ended December 31, 2008 and 2007, respectively. BR charged the Partnership approximately $0.4 million and $5.2 million and in general and administrative expenses for the years ended December 31, 2008 and 2007, respectively. During 2008 and 2007, the Partnership paid approximately $3.6 million and $7.8 million in services to SESI, respectively.

Accounts payable to affiliates is as follows (in thousands):

	December 31,	
	2008	**2007**
Payable to SPN Resources	$ 36	$ 1,268
Payable to Beryl Resources	1,138	817
Payable to Superior Energy Services, Inc.	678	753
Total accounts payable to affiliates	$ 1,852	$ 2,838

 (Continued)

BERYL OIL AND GAS LP
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Unaudited
December 31, 2008 and 2007

(4) Acquisitions and Divestitures

During 2008, the Partnership purchased unproved leases for $1.7 million. The Partnership also purchased additional interest in one of its fields. It paid no cash, but received approximately $1.0 million for the Asset Retirement Obligation (ARO) liability that was assumed.

During 2007, the Partnership sold its interests in one field for the assumption of the related asset retirement obligations, recording a gain of $1.9 million. The Partnership also purchased unproved leases for $0.4 million during 2007.

(5) Property and Equipment

A summary of property and equipment is as follows (in thousands):

	December 31,	
	2008	**2007**
Proved oil and gas properties	$ 665,459	$ 574,565
Unproved oil and gas properties	13,811	40,941
Other	2,794	2,627
	682,064	618,133
Less accumulated depreciation, depletion, and amortization	(239,189)	(162,265)
Property and equipment, net	$ 442,875	$ 455,868

The Partnership recognized $34.9 million and $7.9 million of impairment and dry hole expense during 2008 and 2007, respectively. The impairments comprised proved properties, probable reserves, and unproved leases during 2008 and proved properties and unproved leases during 2007.

Unproved properties comprise a lease bonus that is being amortized over the term of the lease and probable reserve values, which are reviewed annually for impairment. During 2008 and 2007, the Partnership recorded amortization of its unproved properties of $2.2 million and $2.8 million, respectively, which is included in depreciation, depletion, and amortization expense.

Substantially, all of the Partnership s oil and natural gas properties serve as collateral for the Partnership s long-term debt.

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(6) Asset Retirement Obligations

The following table summarizes the activity for the Partnership s asset retirement obligations for the years ended December 31, 2008 and 2007 (in thousands):

	2008	2007
Asset retirement obligations at beginning of year	$ 79,614	$ 89,525
Liabilities acquired and incurred	2,940	
Liabilities settled	(165)	(2,033)
Accretion expense	5,035	5,816
Revision in estimated liabilities	2,660	(13,694)
Asset retirement obligations at end of year	90,084	79,614
Current portion of asset retirement obligations	14,785	2,811
Long-term portion of asset retirement obligations	$ 75,299	$ 76,803

(7) Long-Term Debt

The carrying amount of the Partnership s long-term borrowings that were outstanding subject to interest rate risk consists of the following (in thousands) at:

	December 31,	
	2008	2007
First Lien Term Loan, interest rate based on LIBOR borrowing rates plus a margin of 4.00% payable July 14, 2011, with a rate on December 31, 2008 and 2007 of 6.00% and 9.06%, respectively	$ 179,358	$ 203,602
Second Lien Term Loan, interest rate based on LIBOR borrowing rates plus a margin of 6.00% payable January 13, 2012, with a rate on December 31, 2008 and 2007 of 8.00% and 11.06%, respectively	119,457	119,457
	298,815	323,059
Less current maturities of long-term debt	26,223	24,246
Long-term debt	272,592	298,813
Less unamortized loan discounts	(1,385)	(1,905)
Total long-term debt	$ 271,207	$ 296,908

On July 14, 2006, the Partnership entered into a First Lien Agreement and Second Lien Agreement with Credit Suisse Securities, LLC and Banc of America Securities, LLC to fund its acquisition of oil and gas properties from Noble Energy, Inc. The First Lien Agreement of $311.0 million bears interest at LIBOR plus 4% margin and the Second Lien Agreement of $124 million bears interest at LIBOR plus 6% margin.

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The First Lien Agreement matures on July 14, 2011 and the Second Lien Agreement matures on January 13, 2012. Both agreements require interest payments in March, June, September, and December. The lien agreements contain customary events of default and requires that the Partnership satisfy various financial covenants, which require the Partnership to: (i) maintain a minimum asset coverage ratio, as defined in the lien agreements, (ii) maintain a minimum earnings before interest, taxes, depreciation, abandonment, and exploration and other noncash charges (EBITDAX) to interest ratio, as defined in the lien agreements, and (iii) maintain a leverage ratio, as defined in the lien agreements. The lien agreements also limit the Partnership s capital expenditures, its ability to pay dividends or make other distributions, make acquisitions, make changes to the Partnership s capital structure, create liens, and incur additional indebtedness. The agreements also require the Partnership to enter into interest rate protection agreements and commodity price hedging programs for its debt and sales of natural gas and oil.

The First and Second Lien Agreements with Credit Suisse provide for a Mandatory Prepayment, as defined, which is equal to the Required Percentage of Excess Cash Flow for the period provided that a Liquidity Reserve of $25 million is maintained at all times. Excess Cash Flow is defined as EBITDAX less working capital changes, capital expenditures, and exploration expenses. As of December 31, 2008 and 2007, the Mandatory Prepayment is $0 and $24.2 million, respectively. The First and Second Lien Agreements with Credit Suisse also allows for an Optional Prepayment, equal to no less than $5.0 million and which must be in multiples of $1.0 million. The Optional Prepayment on the First Lien was subject to a prepayment premium of 1% of the Optional Prepayment amount if prepaid within the first year of the loan. The Optional Prepayment on the Second Lien is subject to a prepayment premium of 3%, 2%, and 1%, of the Optional Prepayment amount if prepaid within the first year, second year, and third year, respectively, of the loan. During 2008 and 2007, the Partnership repaid $24.2 million and $111.9 million, respectively, of its outstanding long-term debt and incurred a prepayment penalty of $0 and $0.5 million, which is recorded in interest expense.

The Partnership had a revolving letter of credit facility of $50.0 million during 2007. During 2007, the Partnership terminated its letter of credit facility, which had no outstanding balances and recorded a loss on extinguishment of debt related to unamortized fees of $0.7 million. During 2007, the Partnership recorded $1.7 million in administrative fees related to the letter of credit facility, which is recorded as a component of general and administrative expenses on the statement of operations.

As of December 31, 2008, the Partnership violated the covenant to maintain a leverage ratio of 1.25 to 1.00, or greater, on the First Lien and 1.50 to 1.00, or greater, on the Second Lien. As a result, the Partnership was in default on both the First and Second Lien Agreements. At the point of default, the full amount of both the First and the Second Lien became callable; however, the amounts due were not reclassified to current maturities of long-term debt because the Partnership was recapitalized and the debt was restructured to long-term on October 13, 2009 as discussed in note 13. The restructuring included replacing the First Lien Agreement with an amended agreement and the forgiveness of $27.9 million of amounts due. The Second Lien Term Loan was exchanged for an equity interest in the Partnership. The current maturities of long-term debt of $26.2 million as of December 31, 2008, represent a mandatory prepayment under the restructured Lien Agreements due and paid on October 13, 2009.

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(8) Interest Rate Hedging Agreements

During 2006, the Partnership entered into an interest rate swap on notional amounts of the floating rate term loans, which expired during 2007. During 2006, the Partnership also entered into a collar agreement with a notional cap amount of $50 million and a floor of $25 million of the floating rate term loans, which expired in 2008. Finally during 2006, the Partnership entered into a collar agreement with a notional cap amount of $150 million and a floor of $75 million of floating rate term loans as follows:

Interest rate derivative positions

Contract team		Instrument type	Strike interest rate	Notional amounts	Loan rate
09/06	09/09	Collars	5.4190%	$150 million and $75 million	LIBOR+ %

On October 31, 2008, the Partnership dedesignated its interest rate hedges as cash flow hedges. For the period from November 1, 2008 to December 31, 2008, the Partnership accounted for the change in valuation of the hedges as mark-to-market resulting in an unrealized loss of $0.1 million, recorded in other income.

At December 31, 2008, the fair value of the interest rate derivatives had a short-term liability of $1.9 million, long-term liability of $0, and an unrealized loss of $1.9 million, which is reflected in accumulated other comprehensive income. At December 31, 2007, the fair value of the interest rate derivatives had a short-term liability of $0.2 million, long-term liability of $2.0 million, and an unrealized loss of $2.2 million, which is reflected in other comprehensive loss. These values were based on quoted market prices for contracts with similar terms and maturity dates. During 2008 and 2007, the Partnership (paid) received interest rate settlements from its counterparties of ($1.9 million) and $0.1 million respectively, which are included in interest expense.

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(9) Oil and Gas Commodity Hedging Agreements

The Partnership had the following oil and gas commodity hedging contracts as of December 31, 2008:

Commodity derivatives

Crude oil swaps

Coverage period	Instrument type	Strike price (per Bbl)	Reference or floating price	Total (Bbls)[1]
2009	Swap	$78.32	NYMEX WTI	321,358
2010	Swap	81.47	NYMEX WTI	180,362

Natural gas swaps

Coverage period	Instrument type	Strike price (per MMBtu)	Reference or floating price	Total (MMBtu)[2]
2009	Swap	$8.46	NYMEX	4,390,004
2010	Swap	8.43	NYMEX	2,681,144

Natural gas floors[3]

Coverage period	Instrument type	Strike price (per MMBtu)	Reference or floating price	Total (MMBtu)[2]
2009	Floor	$8.25	NYMEX	7,300,000

(1) Bbls equals Barrel of oil

(2) MMBtu equals Million British Thermal Units

(3) The Partnership paid $2.5 million to purchase these puts in 2008

On October 31, 2008, the Partnership dedesignated its commodity hedges as cash flow hedges. For the period from November 1, 2008 to December 31, 2008, the Partnership accounted for the change in valuation of the hedges as mark-to-market resulting in an unrealized gain of $15.8 million.

For the year ended December 31, 2008, settlements of hedging contracts decreased oil and gas revenues by $20.2 million. For the year ended December 31, 2007, settlements of hedging contracts increased oil and gas revenues by $9.3 million. Settlements expected to be received in the next 12 months related to these commodity hedges of $33.6 million are recorded as an asset in the current portion of the fair value of derivative instruments. Settlements expected to be received after the next 12 months related to these commodity hedges of $6.5 million are recorded as an asset in the long-term portion of the fair value of the derivative instruments. At December 31, 2007, the fair value of the oil and gas commodity derivatives was a short-term asset of $9.5 million and a long-term liability of $12.8 million. As of December 31, 2008 and 2007, $15.7 million and ($8.1 million), respectively, is reflected as an unrealized gain (loss) in accumulated other comprehensive income (loss). As of December 31, 2008 and 2007, $1.6 million and $0.6 million of ineffectiveness was recorded in other income (expense).

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For the years ended December 31, 2008 and 2007, settlements of derivatives that did not qualify for hedge accounting resulted in gains of $1.8 million and $17.8 million, respectively, are included in other income. During 2008 and 2007, the gain (loss) on the fair value of commodity derivatives that are mark-to-market is $17.5 million and $(23.1 million), respectively, and is included in other income (expense).

(10) Fair Value Measurements

The Partnership adopted SFAS No. 157 on January 1, 2008 for the fair value measurements of financials assets and liabilities. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to measurements involving significant unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Partnership has the ability to access at the measurement date.

Level 2 inputs are other than quoted prices included with Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3 inputs are unobservable inputs for the asset or liability.

The level in the fair value hierarchy with a fair value measurement in its entirety falls is based on the lowest level of input that is significant to the fair value measurement in its entirety. The fair value of derivative instruments is determined utilizing pricing models for significantly similar instruments. The models use a variety of techniques to arrive at fair value, including quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties. The credit risk adjustments are based on credit ratings. In certain circumstances, the credit rating represented a significant unobservable input utilized in the valuation.

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The following table presents assets and liabilities that are measured at fair value on a recurring basis (including items that are required to be measured at fair value and items for which the fair value option has been elected) at December 31, 2008 (in thousands):

	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)(1)	Significant unobservable inputs (Level 3)
Assets:			
Commodity derivative instruments	$	$ 40,156	$
	$	$ 40,156	$
Liabilities:			
Interest rate derivative instruments	$	$	$ 1,940
	$	$	$ 1,940

(1) Amounts shown are netted under derivative netting agreements.

The following table presents the Partnership s activity for derivatives measured at fair value on a recurring basis using significant unobservable inputs (Level 3) as defined by SFAS No. 157 for the year ended December 31, 2008 (in thousands):

	Liabilities Interest rate derivatives
Balance at December 31, 2007	$ (2,214)
Total realized and unrealized gains (losses) included in other comprehensive income	2,542
Settlements, net	(1,918)
Reclassification out of accumulated other comprehensive income	(350)
Transfers in and/or out of Level 3	
Balance at December 31, 2008	$ (1,940)

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(11) Other Comprehensive Income (Loss)

The following table reconciles the change in accumulated other comprehensive income (loss) for the years ended December 31, 2008 and 2007 (in thousands):

	December 31,	
	2008	**2007**
Accumulated other comprehensive income (loss), beginning of year	$ (10,346)	$ 13,862
Other comprehensive income (loss):		
Reclassification adjustment for commodity derivative gains (losses) included in net loss	(18,335)	9,254
Change in fair value of commodity derivative instruments	42,137	(31,393)
Commodity derivative other comprehensive income (loss)	23,802	(22,139)
Reclassification adjustment for interest rate derivative gains (losses) included in net loss	(2,268)	84
Change in fair value of interest rate derivative instruments	2,542	(2,153)
Interest rate derivative other comprehensive income (loss)	274	(2,069)
Total other comprehensive income (loss)	24,076	(24,208)
Accumulated other comprehensive income (loss), end of year	$ 13,730	$ (10,346)

(12) Commitments and Contingencies

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

Leases

The Partnership entered into a lease for its office space in Houston, Texas in July 2007 for five years, commencing in October 2007. The annual rental commitment is approximately $0.4 million and escalates each year. During 2008 and 2007, the Partnership incurred rent expense of $0.3 million and $30,000, respectively.

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The following are the Partnership s commitments as of December 31, 2008 and for each of the next five years and in total thereafter (in thousands):

2009	$ 360
2010	369
2011	379
2012	289
Thereafter	
Total	$ 1,397

(13) Subsequent Events

(a) Recapitalization and Restructuring of Second Term Lien Loans

On October 13, 2009, the membership interests of the Partnership were transferred to Dynamic Beryl Holdings, LLC (DBH) through a series of transactions as stated in the Purchase and Contribution Agreement (the Agreement). DBH is owned by Dynamic Offshore Resources, LLC (Dynamic), Superior Energy Investments, LLC (Superior), and the Second Lienholders.

Upon formation of DBH, Dynamic committed to make a capital contribution of $21.9 million in exchange for a 62% interest in DBH; Superior committed to make capital contributions of $8.1 million for a 23% interest in DBH; and the Second Lienholders committed to contribute all outstanding Second Term Lien Loans (including all principal and accrued interest thereon) held by it to DBH in exchange for a 15% interest in DBH. The 15% interest is callable by the Partnership for $50 million for three years following October 13, 2009. After the contribution of the Second Term Lien Loans to DBH, the Partnership entered into a Second Lien Amended and Restated Credit Agreement (the Amended Second Lien Agreement) to replace the First Term Lien Loan.

(b) Amended Second Lien Agreement

On October 13, 2009, the Partnership entered into the Amended Second Lien Agreement in conjunction with the transactions under the Agreement, but prior to DBH taking ownership of the Partnership. The Amended Second Lien Agreement provides that the original remaining balance of the First Term Lien Loans of $179.1 million, together with accrued but unpaid interest is converted into term loans in the aggregate principal amount of $151.2 million (the difference was forgiven by the First Term Lienholders). Immediately after DBH taking ownership of the Partnership, the Partnership made a mandatory prepayment under the Amended Second Lien Agreement in the amount of $26.2 million, leaving a new remaining balance under the Amended Second Lien Agreement of $125.0 million.

The Amended Second Lien Agreement bears interest at a rate equal to the higher of (i) LIBOR or (ii) 3%, plus a margin of 5%. Interest is payable on the last business day of March, June, September, and December. The Amended Second Lien Agreement matures on October 13, 2014. Obligations under the Amended Second Lien Agreement are secured by second priority liens on substantially all of the Partnership s assets. The Amended Second Lien Agreement contains customary events of

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default and requires that the Partnership satisfy various financial covenants, which require the Partnership to: (i) maintain a leverage ratio, as defined in the Amended Second Lien Agreement; (ii) maintain an interest coverage ratio, as defined in the Amended Second Lien Agreement; and (iii) maintain a current ratio, as defined in the Amended Second Lien Agreement. The requirements to maintain a leverage ratio and an interest coverage ratio do not become effective until the fiscal quarter ending September 30, 2011. The Amended Second Lien Agreement also limits the Partnership s ability to pay dividends or make other distributions, make acquisitions, create liens, and incur additional indebtedness. The Partnership is also required to enter into commodity price hedging agreements for its sales of natural gas and oil.

The Amended Second Lien Agreement provides for a mandatory prepayment of $20 million within 180 days of closing unless the Partnership incurs in excess of $20 million in uninsured damages as the result of hurricane(s) occurring during such period. In addition, to the extent the Partnership sells assets in excess of $5 million in the aggregate, 50% of the net cash proceeds in excess of such amount must be used to prepay amounts outstanding under the Amended Second Lien Agreement. There is no required, periodic amortization of the Amended Second Lien Agreement. The Partnership does have the ability to make Optional Prepayments, equal to no less than $1 million and which must be in multiples of $1 million with no prepayment penalty premium. Amounts prepaid may not be reborrowed.

(c) Revolving Credit Facility

Also, on October 13, 2009, after DBH taking ownership of the Partnership, the Partnership entered into a revolving credit facility to provide for a three-year $25.0 million revolving credit facility (the Revolver). The initial borrowing base under the Revolver was $10.0 million with initial availability of $4.0 million. The full amount available under the Revolver is also available for the issuance of letters of credit.

The Revolver is subject to semiannual borrowing base redeterminations on April 1 and October 1 of each year. In addition to the scheduled semiannual borrowing base redetermination, the lenders or the Partnership have the right to redetermine the borrowing base at any time, provided that no party can request more than one such redetermination between the regularly scheduled borrowing base redeterminations. The determination of our borrowing base is subject to a number of factors, including the quantities of proved oil and natural gas reserves, the lenders price assumptions and other various factors, some of which may be out of our control. Our lenders can redetermine the borrowing base to a lower level than the current borrowing base if they determine that our oil and natural gas reserves, at the time of redetermination, are inadequate to support the borrowing base then in effect. In this case, the Partnership would be required to make three monthly payments each equal to one third of the amount by which the aggregate outstanding loans and letters of credit exceed the borrowing base.

Obligations under the Revolver are secured by first priority liens on substantially all of the Partnership s assets. The Revolver also contains other restrictive covenants, including, among other items, maintenance of a leverage ratio, an interest coverage ratio, and a current ratio (all as defined in the Revolver), restriction on cash dividends, and restrictions on incurring additional indebtedness.

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Under the Revolver, outstanding balances bear interest at either the alternate base rate plus a margin (based on a sliding scale of 1.50% to 2.25% based upon borrowing base usage) or LIBOR plus a margin (based on a sliding scale of 2.50% to 3.25%, based upon borrowing base usage). The alternate base rate is equal to the higher of (i) the Royal Bank of Scotland plc s prime rate; (ii) the federal funds rate plus 0.50%; or (iii) LIBOR plus 1.00%. LIBOR is equal to the applicable British Bankers Association LIBO rate for deposits in U.S. dollars. The Revolver also provides for commitment fees of 0.50% calculated on the difference between the borrowing base and the aggregate outstanding loans and letters of credit under the Revolver.

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Supplemental Oil and Gas Disclosure

The following information is provided pursuant to, and developed utilizing procedures prescribed by, Statement of Financial Accounting Standards (SFAS) No. 69, *Disclosures about Oil and Gas Producing Activities* an amendment of FASB Statements 19, 25, 33, and 39. The supplemental data presented herein reflect information for all of its crude oil, natural gas, and natural gas liquids (NGL) producing activities. All of the Partnership s operations and reserves are in the United States of America.

Oil and Gas Reserves

The Partnership s estimates as of December 31, 2008 and 2007 of proved reserves are based on reserve reports prepared by Netherland Sewell & Associates, Inc., independent petroleum engineers. Users of this information should be aware that the process of estimating quantities of proved and proved-developed crude oil, natural gas reserves is very complex, requiring significant subjective decision making in the analysis and evaluation of all geological, engineering, and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including additional development activity, additional production data, evolving production history, and continual reassessment of the viability of production under different economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates 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 Partnership s net proved reserves, including changes therein, and proved developed reserves:

	Crude oil (Mbbls)	Natural gas (Mmcf)
Proved reserves:		
December 31, 2006	4,940	88,837
Purchases of reserves in place		
Extensions and discoveries	49	9,986
Revisions of prior estimates	864	(5,747)
Production	(1,274)	(17,430)
December 31, 2007	4,579	75,646
Purchases of reserves in place		
Extensions and discoveries	702	13,011
Revisions of prior estimates	(472)	(150)
Production	(889)	(11,704)
December 31, 2008	3,920	76,803

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	Crude oil (Mbbls)	Natural gas (Mmcf)
Proved-developed reserves:		
December 31, 2007	3,937	56,081
December 31, 2008	3,385	66,752

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities

Costs incurred, on an accrual basis, represent amounts capitalized or expensed by the Partnership for property acquisition, exploration, and development activities. Costs incurred for property acquisitions, exploration, and development activities were as follows (in thousands):

	December 31, 2008	2007
Acquisitions of properties proved	$	$
Acquisitions of properties unproved	1,653	389
Total acquisition costs incurred	1,653	389
Exploration costs	44,270	5,134
Development costs	45,630	48,925
Total costs incurred	$ 91,553	$ 54,448

Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves

The following information has been developed utilizing procedures prescribed by SFAS No. 69. It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating the Partnership 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 (Standardized Measure) be viewed as representative of the current value of the Partnership.

The Partnership 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 required by SFAS No. 69 and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues.

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Under the Standardized Measure, future cash inflows were estimated by applying period-end oil and natural gas prices adjusted for differentials provided by the Partnership. 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. Use of a 10% discount rate is required by SFAS No. 69. No income tax estimates are incorporated, as the Partnership does not pay federal income tax.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows for the years ended December 31, 2008 and 2007 (in thousands) is as follows:

	2008	2007
Future cash inflows	$ 628,444	$ 980,942
Future production costs	(171,496)	(142,559)
Future development and abandonment costs	(199,692)	(199,156)
Future net cash flows	257,256	639,227
10% annual discount for estimated timing of cash flows	(58,935)	(158,461)
Standardized measure of discounted future net cash flows	$ 198,321	$ 480,766

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, 2008 and 2007 (in thousands) is as follows:

	2008	2007
Beginning of year	$ 480,766	$ 370,912
Sales and transfers of oil and natural gas produced, net of production costs	(136,609)	(185,273)
Net changes in prices and production costs	(237,276)	175,181
Net changes in estimated future development costs	(35,590)	(56,596)
Extensions and discoveries	60,475	62,890
Revisions of quantity estimates	(10,473)	(3,457)
Development costs incurred	45,630	54,448
Purchase and sales of reserves in place		
Changes in production rates (timing) and other	(9,377)	25,570
Accretion of discount	40,775	37,091
Net increase (decrease)	(282,445)	109,854
End of year	$ 198,321	$ 480,766

The discounted future and net cash flows at December 31, 2008 amount was estimated by Netherland Sewell & Associates using a period-end crude West Texas Intermediate price of $41.00 per Bbl, a Henry Hub gas price of $5.71 per MMBtu, and price differentials provided by the Partnership. The discounted future and net cash flows at December 31, 2007 amount was estimated by Netherland Sewell & Associates using a period-end crude West Texas Intermediate price of $96.01 per Bbl, a Henry Hub gas price of $6.80 per MMBtu, and price differentials provided by the Partnership.