PLAINS ALL AMERICAN PIPELINE LP
Form S-1
October 14, 2004

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As filed with the Securities and Exchange Commission on October 14, 2004

Registration No. 333-

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM S-1

**REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933**

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**4610**	**76-0582150**
(State or Other Jurisdiction of Incorporation or Organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

**333 Clay Street, Suite 1600
Houston, Texas 77002
(713) 646-4100**
(Address, Including Zip Code, and Telephone Number, including Area Code, of Registrant's Principal Executive Offices)

**Tim Moore
Vice President and General Counsel
333 Clay Street, Suite 1600
Houston, Texas 77002
(713) 646-4100**
(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Copies to:
**David P. Oelman
Vinson & Elkins L.L.P.
1001 Fannin Street, Suite 2300
Houston, Texas 77002
(713) 758-2222**

Approximate date of commencement of proposed sale to the public: From time to time after this Registration Statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ý

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

CALCULATION OF REGISTRATION FEE

Title Of Each Class Of Securities To Be Registered	Amount to be Registered[(1)]	Proposed Maximum Offering Price Per Unit[(2)]	Proposed Maximum Aggregate Offering Price[(1)(2)]	Amount of Registration Fee
Common Units representing limited partner interests[(1)]	3,245,700 units	$36.40	$118,143,480[(2)]	$14,969[(2)]

(1) Includes the resale of 3,245,700 common units issuable upon the conversion of Class C common units into common units.

(2) Estimated solely for the purpose of determining the registration fee on the basis of the average high and low prices of the common units on the New York Stock Exchange on October 11, 2004.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to Completion, Dated October , 2004

P R O S P E C T U S

3,245,700 Common Units

Plains All American Pipeline, L.P.

Representing Limited Partner Interests

Up to 3,245,700 of our common units may be offered from time to time by the selling unitholders named in this prospectus. The selling unitholders may sell the common units at various times and in various types of transactions, including sales in the open market, sales in negotiated transactions and sales by a combination of methods. We will not receive any proceeds from the sale of common units by the selling unitholders.

Our common units are listed on the New York Stock Exchange under the symbol "PAA."

Limited partnerships are inherently different from corporations. You should carefully consider each of the factors described under "Risk Factors" which begins on page 2 of this prospectus before you make an investment in the securities.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR DETERMINED IF THIS PROSPECTUS IS TRUTHFUL OR COMPLETE. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

In connection with certain sales of securities hereunder, a prospectus supplement may accompany this prospectus.

The date of this prospectus is October , 2004

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission, or SEC, using a "shelf" registration process. Under this shelf process, the selling unitholders may sell up to 3,245,700 of our common units. In connection with certain sales of securities hereunder, a prospectus supplement may accompany this prospectus. The prospectus supplement may also add, update or change information contained in this prospectus. Therefore, before you invest in our securities, you should read this prospectus and any attached prospectus supplements.

In this registration statement, the terms "we," "our," "ours," and "us" refer to Plains All American Pipeline, L.P. and its subsidiaries, unless otherwise indicated or the context requires otherwise.

WHO WE ARE

General

We are a publicly traded Delaware limited partnership engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products. We refer to liquefied petroleum gas and other petroleum products collectively as "LPG." We have an extensive network of pipeline transportation, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada. Several members of our existing management team founded this midstream crude oil business in 1992, and we completed our initial public offering in 1998.

We have operations in the United States and Canada, which can be categorized into two primary business activities: crude oil pipeline transportation operations and gathering, marketing, terminalling and storage operations.

Business Strategy

Our principal business strategy is to capitalize on the regional crude oil supply and demand imbalances that exist in the United States and Canada by combining the strategic location and distinctive capabilities of our transportation and terminalling assets with our extensive marketing and distribution expertise to generate sustainable earnings and cash flow.

We intend to execute our business strategy by:

- increasing and optimizing throughput on our existing pipeline and gathering assets and realizing cost efficiencies through operational improvements;
- utilizing and expanding our Cushing Terminal and our other assets to service the needs of refiners and to profit from merchant activities that take advantage of crude oil pricing and quality differentials;
- selectively pursuing strategic and accretive acquisitions of crude oil transportation assets, including pipelines, gathering systems, terminalling and storage facilities and other assets that complement our existing asset base and distribution capabilities;
- optimizing and expanding our Canadian operations and our presence in the Gulf Coast and Gulf of Mexico to take advantage of anticipated increases in the volume and qualities of crude oil produced in these areas; and
- prudently and economically leveraging our asset base, knowledge base and skill sets to participate in energy businesses that are closely related to, or significantly intertwined with the crude oil business.

To a lesser degree, we also engage in a similar business strategy with respect to the wholesale marketing and storage of LPG, which we began as a result of an acquisition in mid-2001.

RISK FACTORS

You should carefully consider the following risk factors together with all of the other information included in this prospectus in evaluating an investment in us. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Risks Related to Our Business

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. Production from these offshore fields has experienced substantial production declines since 1995.

A significant portion of our segment profit is derived from pipeline transportation margins associated with the Santa Ynez and Point Arguello fields located offshore California. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. We estimate that a 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline segment profit of approximately $3.1 million. In addition, any production disruption from these fields due to production problems, transportation problems or other reasons would have a material adverse effect on our business.

Our trading policies cannot eliminate all price risks. In addition, any non-compliance with our trading policies could result in significant financial losses.

Generally, it is our policy that as we purchase crude oil we establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation under futures contracts on the NYMEX and over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is generally not to acquire and hold crude oil, futures contracts or derivative products for the purpose of speculating on price changes. This policy cannot, however, eliminate all price risks. For example, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. While this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations. In addition, any event that disrupts our anticipated physical supply of crude oil could expose us to risk of loss resulting from price changes. Moreover, we are exposed to some risks that are not hedged, including certain basis risks and price risks on certain of our inventory, such as pipeline linefill, which must be maintained in order to transport crude oil on our pipelines.

In addition, our trading operations involve the risk of non-compliance with our trading policies. For example, we discovered in November 1999 that our trading policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181.0 million. We have taken steps within our organization to enhance our processes and procedures to detect future unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our trading policies and procedures, particularly if deception or other intentional misconduct is involved.

If we do not make acquisitions on economically acceptable terms our future growth may be limited.

Our ability to grow and to increase distributions to unitholders is substantially dependent on our ability to make acquisitions that result in an increase in adjusted operating surplus per unit. If we are unable to make such accretive acquisitions either because (i) we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (ii) we are unable to raise financing for such acquisitions on economically acceptable terms or (iii) we are outbid by competitors, our future growth and ability to raise distributions will be limited. In particular, competition for midstream assets and businesses has intensified substantially and as a result such assets and businesses have become more costly. As a result, we may not be able to complete the number or size of acquisitions that we have targeted internally or to continue to grow as quickly as we have historically.

Our acquisition strategy requires access to new capital. Tightened credit markets or other factors which increase our cost of capital could impair our ability to grow.

Our business strategy is substantially dependent on acquiring additional assets or operations that will allow us to increase distributions to unitholders. We continuously consider and enter into discussions regarding potential acquisitions. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. Any material acquisition will require access to capital. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our ability to execute our acquisition strategy. Our ability to maintain our targeted credit profile, including maintaining our credit ratings, could impact our cost of capital as well as our ability to execute our acquisition strategy.

Our acquisition strategy involves risks that may adversely affect our business.

Any acquisition involves potential risks, including:

- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;
- customer or key employee loss from the acquired businesses; and
- the diversion of management's attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to make distributions to you.

The nature of our assets and business could expose us to significant environmental compliance costs and liabilities.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil and are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment. Compliance with these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and even the issuance of injunctions that may restrict or prohibit our operations. Environmental laws and regulations are subject to change, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material affect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and any claims made by neighboring landowners and other third parties for personal injury and property damage.

The profitability of our pipeline operations depends on the volume of crude oil shipped by third parties.

Third party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. For example, we estimate that an average 10,000 barrel per day variance in the Basin Pipeline System, equivalent to an approximate 4% volume variance on that pipeline system, would change annualized segment profit by approximately $1.0 million.

The success of our business strategy to increase and optimize throughput on our pipeline and gathering assets is dependent upon our securing additional supplies of crude oil.

Our operating results are dependent upon securing additional supplies of crude oil from increased production by oil companies and aggressive lease gathering efforts. The ability of producers to increase production is dependent on the prevailing market price of oil, the exploration and production budgets of the major and independent oil companies, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives and other matters beyond our control. There can be no assurance that production of crude oil will rise to sufficient levels to cause an increase in the throughput on our pipeline and gathering assets.

Our operations are dependent upon demand for crude oil by refiners in the Midwest and on the Gulf Coast. Any decrease in this demand could adversely affect our business.

Demand for crude oil is dependent upon the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand. Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets, and any decrease in this demand could adversely affect our business.

We face intense competition in our terminalling and storage activities and gathering and marketing activities.

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control greater supplies of crude oil. We estimate that a $0.01 per barrel variance in the aggregate average segment profit would have an approximate $2.5 million annual effect on segment profit.

The profitability of our gathering and marketing activities is generally dependent on the volumes of crude oil we purchase and gather.

To maintain the volumes of crude oil we purchase, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines in crude oil production from depleting wells or volumes lost to competitors. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is low and competition to gather available production is intense. Generally, because producers experience inconveniences in switching crude oil purchasers, such as delays in receipt of proceeds while awaiting the preparation of new division orders, producers typically do not change purchasers on the basis of minor variations in price. Thus, we may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil. We estimate that a 5,000 barrel per day decrease in barrels gathered by us would have an approximate $1.0 million per year negative impact on segment profit. This impact is based on a reasonable margin throughout various market conditions. Actual margins vary based on the location of the crude oil, the strength or weakness of the market and the grade or quality of crude oil.

We are exposed to the credit risk of our customers in the ordinary course of our gathering and marketing activities.

There can be no assurance that we have adequately assessed the credit-worthiness of our existing or future counter-parties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

In those cases where we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all parties. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk, and there can be no assurance that we will not experience losses in dealings with other parties.

Our pipeline assets are subject to federal, state and provincial regulation.

Our domestic interstate common carrier pipelines are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be just and reasonable and non-discriminatory. Our intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

Our Canadian pipeline assets are subject to regulation by the National Energy Board and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these Canadian agencies has the power to determine the rates we are allowed to charge for transportation on such pipeline. The extent to which regulatory agencies can override existing transportation contracts has not been fully decided.

Our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets.

Reduced throughput on these interconnecting pipelines as a result of testing, line repair, reduced operating pressures or other causes could result in reduced throughput on our pipeline systems that would adversely affect our profitability.

Fluctuations in demand can negatively affect our operating results.

Fluctuations in demand for crude oil, such as caused by refinery downtime or shutdown, can have a negative effect on our operating results. Specifically, reduced demand in an area serviced by our transmission systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by our ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

The terms of our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities.

As of June 30, 2004, pro forma for the third quarter equity and debt offerings, our total outstanding long-term debt was approximately $797.1 million. Various limitations in our indebtedness may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Changes in currency exchange rates and foreign currency restrictions and shortages could adversely affect our operating results.

Because we conduct operations in Canada, we are exposed to currency fluctuations and exchange rate risks that may adversely affect our results of operations. In addition, legal restrictions or shortages in currencies outside the U.S. may prevent us from converting sufficient local currency to enable us to comply with our currency placement obligations not denominated in local currency or to meet our operating needs and debt service requirements.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce our ability to make distributions to you.

If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate rate. Treatment of us as a corporation would cause a material reduction in our anticipated cash flow, which would materially and adversely affect our ability to make distributions to you.

In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Imposition of such forms of taxation would reduce our cash flow.

We will be required to comply with Section 404 of the Sarbanes-Oxley Act for the first time.

The Sarbanes-Oxley Act of 2002 has imposed many new requirements on public companies regarding corporate governance and financial reporting. Among these is the requirement under Section 404 of the Act, beginning with our 2004 Annual Report, for management to report on our internal control over financial reporting and for our independent public accountants to attest to management's report. During 2003, we commenced actions to enhance our ability to comply with these requirements, including but not limited to the addition of staffing in our internal audit department, documentation of existing controls and implementation of new controls or modification of existing controls as deemed appropriate. We have continued to devote substantial time and resources to the documentation and testing of our controls, and to planning for and implementation of remedial efforts in those instances where remediation is indicated. At this point, we have no indication that management will be unable to favorably report on our internal controls nor that our independent auditors will be unable to attest to management's findings. Both we and our auditors, however, must complete the process (which we have never completed before), so we cannot assure you of the results. It is unclear what impact failure to comply fully with Section 404 or the discovery of a material weakness in our internal control over financial reporting would have on us, but presumably it could result in the reduced ability to obtain financing, the loss of customers, and additional expenditures to meet the requirements.

Risks Inherent in an Investment in Plains All American Pipeline

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to you.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner.

You may not be able to remove our general partner even if you wish to do so.

Our general partner manages and operates Plains All American Pipeline. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect the general partner or the directors of the general partner on an annual or other continuing basis. Because the owners of our general partner own more than one-third of our outstanding units, these owners have the practical ability to prevent the removal of our general partner.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- if the holders, including the general partner and its affiliates, of at least $66^2/_3$% of the units vote to remove the general partner without cause, existing arrearages on the common units will be extinguished and the common units will no longer be entitled to arrearages if we fail to pay the minimum quarterly distribution in any quarter. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our general partner.

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

We may issue additional common units without your approval, which would dilute your existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units, without your approval. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- your proportionate ownership interest in Plains All American Pipeline will decrease;

- the amount of cash available for distribution on each unit may decrease;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the common units may decline.

We may also issue at any time an unlimited number of equity securities ranking junior to the common units without the approval of the unitholders.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, you may be required to sell your common units at a time when you may not desire to sell them or at a price that is less than the price you would like to receive. You may also incur a tax liability upon a sale of your common units.

You may not have limited liability if a court finds that unitholder actions constitute control of our business.

Under Delaware law, you could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

- we do not have any employees and we rely solely on employees of the general partner and its affiliates;
- under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;
- the amount of cash expenditures, borrowings and reserves in any quarter may affect available cash to pay quarterly distributions to unitholders;
- the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner's liability;
- under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not the result of arms length negotiations; and
- the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

Tax Risks to Common Unitholders

You should read "Tax Considerations" for a more complete discussion of the following expected material federal income tax consequences of owning and disposing of common units.

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to you.

The anticipated after-tax benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%. Distributions to you would generally be taxed again to you as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon

us as a corporation, the cash available for distribution to you would be substantially reduced. Treatment of us as a corporation would result in a material reduction in the after-tax return to the unitholders, likely causing a substantial reduction in the value of the common units.

Current law may change so as to cause us to be taxed as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect that impact on us.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for common units.

We have not requested a ruling from the IRS with respect to any matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this registration statement or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain our counsel's conclusions or the positions we take. A court may not concur with our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for common units and the price at which they trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne by us and directly or indirectly by the unitholders and the general partner.

You may be required to pay taxes even if you do not receive any cash distributions.

You will be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you do not receive any cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from your share of our taxable income.

Tax gain or loss on disposition of common units could be different than expected.

If you sell your common units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in those common units. Prior distributions in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that common unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that common unit, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you. Should the IRS successfully contest some positions we take, you could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years. Also, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

If you are a tax-exempt entity, a regulated investment company or an individual not residing in the United States, you may have adverse tax consequences from owning common units.

Investment in common units by tax-exempt entities, regulated investment companies or mutual funds and foreign persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Very little of our income will be qualifying income to a regulated investment company or mutual fund. Distributions to foreign persons will be reduced by withholding taxes at the highest effective U.S.

federal income tax rate for individuals, and foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We are registered as a tax shelter. This may increase the risk of an IRS audit of us or a unitholder.

We are registered with the IRS as a "tax shelter." Our tax shelter registration number is 99061000009. The IRS requires that some types of entities, including some partnerships, register as "tax shelters" in response to the perception that they claim tax benefits that the IRS may believe to be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a 1% profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in the unitholders' tax returns and may lead to audits of unitholders' tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return.

Recently issued Treasury Regulations require taxpayers to report certain information on Internal Revenue Service Form 8886 if they participate in a "reportable transaction." Unitholders may be required to file this form with the IRS if we participate in a "reportable transaction." A transaction may be a reportable transaction based upon any of several factors. Unitholders are urged to consult with their own tax advisor concerning the application of any of these factors to their investment in our common units. Congress is considering legislative proposals that, if enacted, would impose significant penalties for failure to comply with these disclosure requirements. The Treasury Regulations also impose obligations on "material advisors" that organize, manage or sell interests in registered "tax shelters." As stated above, we have registered as a tax shelter, and, thus, one of our material advisors will be required to maintain a list with specific information, including unitholder names and tax identification numbers, and to furnish this information to the IRS upon request. Unitholders are urged to consult with their own tax advisor concerning any possible disclosure obligation with respect to their investment and should be aware that we and our material advisors intend to comply with the list and disclosure requirements.

We treat a purchaser of units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization positions that do not conform with all aspects of the Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to your tax returns. Please read "Tax Considerations Uniformity of Units" in this prospectus for further discussion of the effect of the depreciation and amortization positions we have adopted.

You will likely be subject to foreign, state and local taxes in jurisdictions where you do not live as a result of an investment in units.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign taxes, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property and in which you do not reside. We own property and conduct business in Canada and in most states in the United States. You may be required to file Canadian federal income tax returns and to pay Canadian federal and provincial income taxes and to file state and local income tax returns and pay state and local income taxes in many or all of the jurisdictions in which we do business or own property. Further, you may be subject to penalties for failure to comply with those requirements. It is your responsibility to file all federal, state, local and foreign tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in the common units.

USE OF PROCEEDS

We will not receive any proceeds from the sale of common units by the selling unitholders.

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

As of September 30, 2004, there were 62,740,218 common units outstanding, held by approximately 340 holders of record, including common units held in street name. The common units are traded on the New York Stock Exchange under the symbol "PAA." An additional 1,307,190 Class B common units and 3,245,700 Class C common units were outstanding as of such date. The Class B common units are held by an affiliate of Plains Holdings Inc. and the Class C common units are held by six holders of record. The Class B common units and the Class C common units are *pari passu* with and have economic terms substantially similar to the common units but are not publicly traded. Holders of the Class B common units and the Class C common units have the right to demand a meeting of limited partners to vote on whether the Class B common units and Class C common units may be converted at the option of the holders into an equal number of common units. We anticipate that notice of the exercise of such right will be given on October 15, 2004.

The following table sets forth, for the periods indicated, the high and low sales prices for the common units, as reported on the New York Stock Exchange Composite Transactions Tape, and quarterly cash distributions declared per common unit. The last reported sale price of common units on the New York Stock Exchange on October 11, 2004 was $36.41 per common unit.

	Price Range		Cash Distributions per Unit[1]
	High	Low	
2002			
First Quarter	$ 26.79	$ 23.60	$ 0.5250
Second Quarter	27.30	24.60	0.5375
Third Quarter	26.38	19.54	0.5375
Fourth Quarter	24.44	22.04	0.5375
2003			
First Quarter	$ 26.90	$ 24.20	$ 0.5500
Second Quarter	31.48	24.65	0.5500
Third Quarter	32.49	29.10	0.5500
Fourth Quarter	32.82	29.76	0.5625
2004			
First Quarter	$ 35.23	$ 31.18	$ 0.5625
Second Quarter	36.13	27.25	0.5775
Third Quarter	35.98	31.63	[2]
Fourth Quarter (through October 11, 2004)	36.99	35.76	[2]

(1) Represents cash distributions attributable to the quarter and paid within 45 days after the quarter.

(2) The distributions attributable to the third and fourth quarters of 2004 have not yet been declared or paid.

SELECTED HISTORICAL FINANCIAL AND OPERATING DATA

We have derived the historical financial information and operating data below from our audited consolidated financial statements as of and for the years ended December 31, 2003, 2002, 2001, 2000 and 1999 and from our unaudited financial statements as of and for the six months ended June 30, 2004 and 2003. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this prospectus.

	Six Months Ended June 30,		Year Ended December 31,				
	2004	2003	2003	2002	2001	2000	1999
	(in millions except per unit data)						
Statement of operations data:							
Revenues	$ 8,936.4	$ 5,991.1	$ 12,589.8	$ 8,384.2	$ 6,868.2	$ 6,641.2	$ 10,910.4
Cost of sales and field operations (excluding LTIP charge)	8,782.2	5,878.2	12,366.6	8,209.9	6,720.9	6,506.5	10,800.1
Unauthorized trading losses and related expenses						7.0	166.4
Inventory valuation adjustment					5.0		
LTIP charge operations[1]	0.5		5.7				
General and administrative expenses (excluding LTIP charge)	35.1	25.2	50.0	45.7	46.6	40.8	23.2
LTIP charge general and administrative[1]	3.7		23.1				
Depreciation and amortization	29.1	22.2	46.8	34.0	24.3	24.5	17.3
Restructuring expense							1.4
Total costs and expenses	8,850.6	5,925.6	12,492.3	8,289.6	6,796.8	6,578.8	11,008.4
Gain on sale of assets			0.6		1.0	48.2	16.4
Operating income	85.7	65.4	98.2	94.6	72.4	110.6	(81.6)
Interest expense	(19.5)	(17.7)	(35.2)	(29.1)	(29.1)	(28.7)	(21.1)
Interest income and other, net[2]	0.5		(3.6)	(0.2)	0.4	(4.4)	(0.6)
Income (loss) from continuing operations before cumulative effect of change in accounting principle[12]	$ 66.7	$ 47.7	$ 59.4	$ 65.3	$ 43.7	$ 77.5	$ (103.4)
Basic net income (loss) per limited partner unit before cumulative effect of change in accounting principle[2][12]	$ 1.03	$ 0.87	$ 1.01	$ 1.34	$ 1.12	$ 2.13	$ (3.21)
Diluted net income (loss) per limited partner unit before cumulative effect of change in accounting principle[2][12]	$ 1.03	$ 0.87	$ 1.00	**High**	**Low**		

	Six Months Ended June 30,	Year Ended December 31,
2010		
First Quarter	$ 26.95	$ 19.40
Second Quarter	28.93	18.09
Third Quarter	28.00	18.02
Fourth Quarter	35.44	25.35
2011		
First Quarter	$ 41.65	$ 32.55
Second Quarter	41.49	33.39
Third Quarter	42.87	26.21
Fourth Quarter	31.44	22.19

As of February 17, 2012, there were 157,592,337 shares of our common stock outstanding, which were held by 152 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. In addition, the terms of our credit facility and the indentures governing all of our unsecured senior notes 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 of this Annual Report.

Issuer Purchases of Equity Securities

In December 2009, our Board of Directors approved a $350 million share repurchase program that expired on December 31, 2011 and was not renewed. The following table provides information about our common stock repurchased and retired during each month for the three months ended December 31, 2011:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan (2)	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plan (2)
October 1 31, 2011	1,184	$ 26.76		$ 350,000,000
November 1 30, 2011		$		$ 350,000,000
December 1 31, 2011		$		$ 350,000,000
October 1, 2011 through December 31, 2011	1,184	$ 26.76		$ 350,000,000

(1) Through our stock incentive plans, 1,184 shares were delivered to us by our employees to satisfy their tax withholding requirements upon vesting of restricted stock.

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(2) There was no common stock repurchased and retired under the share repurchase program during the quarter ended December 31, 2011.

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.

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 Self-Determined Peer Groups, as described below, for the same period. The information in the graph is based on the assumption of a $100 investment on January 1, 2007 at closing prices on December 31, 2006.

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.

	Years Ended December 31,				
	2007	2008	2009	2010	2011
Superior Energy Services, Inc.	$ 105	$ 49	$ 74	$ 107	$ 87
S&P 500 Stock Index	$ 105	$ 66	$ 84	$ 97	$ 99
Peer Group (current)	$ 146	$ 61	$ 101	$ 136	$ 120
Peer Group (prior)	$ 146	$ 52	$ 87	$ 122	$ 114

NOTES:

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

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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, 2006.

For 2011, we amended our Self-Determined Peer Group as a result of the Complete acquisition as well as mergers involving other companies in our peer group. We believe our current Self-Determined Peer Group better reflects our current size as well as our potential for growth. Our current Self-Determined Peer Group consists of 16 companies whose average stockholder return levels comprise part of the performance criteria established by the Compensation Committee under our long-term incentive compensation program: Baker Hughes, Incorporated, Basic Energy Services, Inc., Cameron International Corp., FMC Technologies Inc., Halliburton Co., Helix Energy Solutions Group, Inc., Helmerich & Payne Inc., Key Energy Services, Inc., Nabors Industries Ltd., National Oilwell Varco, Inc., Oceaneering International, Inc., Oil States International, Inc., Patterson-UTI Energy Inc., RPC, Inc., Schlumberger Ltd. and Weatherford International, Ltd. Our prior Self-Determined Peer Group included Baker Hughes, Incorporated, Basic Energy Services, Inc., Cameron International Corp., Complete Production Services, Inc., Global Industries, Ltd., Helix Energy Solutions Group, Inc., Hercules Offshore, Inc., Key Energy Services, Inc., National Oilwell Varco, Inc., Oceaneering International, Inc., Oil States International, Inc., RPC, 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. The financial data is in thousands, except per share amounts.

	Years Ended December 31,				
	2011	2010	2009	2008	2007
Revenues	$ 2,070,166	$ 1,681,616	$ 1,449,300	$ 1,881,124	$ 1,572,467
Income (loss) from operations	273,745	168,266	(51,384)	565,692	465,838
Net income (loss)	142,554	81,817	(102,323)	351,475	271,558
Net income (loss) per share:					
Basic	1.79	1.04	(1.31)	4.39	3.35
Diluted	1.76	1.03	(1.31)	4.33	3.30
Total assets	4,048,145	2,907,533	2,516,665	2,490,145	2,255,295
Long-term debt, net	1,685,087	681,635	848,665	654,199	637,789
Decommissioning liabilities, less current portion	108,220	100,787			88,158
Stockholders equity	1,453,599	1,280,551	1,178,045	1,254,273	1,025,666

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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, 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.

Executive Summary

On February 7, 2012, we acquired Complete Production Services, Inc. (Complete) pursuant to a merger that substantially expanded the size and scope of our business. Except as otherwise noted, the description of our business contained in this Item 7 refers to the business of Superior and its consolidated subsidiaries, including Complete and its subsidiaries, except where we refer to results of operations or operating data prior to February 7, 2012. However, because the Complete acquisition occurred during the 2012 fiscal year, but prior to our filing of this Annual Report, the accompanying financial statements reflect the results of Superior s stand-alone operations as of December 31, 2011. Additional information on our acquisition of Complete is included in note 3 of our consolidated financial statements included in Part II, Item 8 of this Annual Report. Additionally, on February 22, 2012, we entered into an agreement to sell our marine segment, consisting of a fleet of 18 liftboats.

We believe we are a leading, highly diversified provider of specialized oilfield services and equipment. As a result of the Complete acquisition, we significantly added to our U.S. land geographic footprint and product and service offering. We now offer a wider variety of products and services throughout the economic life of an oil and gas well. The acquisition of Complete greatly expanded our ability to offer more products and services related to the completion of a well prior to full production commencing, and enhanced our full suite of intervention services used to carry out wellbore maintenance operations during a well s producing phase.

We serve energy industry customers who focus on developing and producing oil and gas worldwide. Our operations are managed and organized by both business units and geomarkets offering product and service families within various phases of a well s economic lifecycle, including end of life services. Business unit and geomarket leaders report to executive vice presidents, and we report our operating results in three segments: Subsea and Well Enhancement, Drilling Products and Services and Marine. Given our history of growth and long-term strategy of expanding geographically, we provide supplemental segment revenue information in three geographic areas: (1) U.S. land; (2) Gulf of Mexico; and (3) international.

Overview of our business segments

The subsea and well enhancement segment consists of completion and workover services, production services and subsea and technical solutions, all of which are labor and equipment intensive. In 2011, approximately 42% of segment revenue was from the U.S. land market area (up from 34% in 2010), while approximately 32% of this segment s revenue was derived from work performed for customers in the Gulf of Mexico market area (down from 40% in 2010) and approximately 27% of segment revenue was from international market areas (which remained constant from 2010).

Following the acquisition of Complete, a significantly larger amount of revenue from this segment is expected to come from the U.S. land market areas. We intend to continue to focus our capital expenditures on expanding our existing products and services into U.S. land market areas that are driven by oil and liquids-rich drilling and completion activity, and on expanding into new and existing international market areas. In the U.S., the acquisition of Complete will allow us to take advantage of opportunities with larger oil and gas producers that procure services from providers offering multiple and complementary product lines. This segment s income from operations as a percentage of segment revenue (operating margin) can vary based on drilling and completion spending and activity, especially in the U.S. land market areas.

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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. The financial performance is primarily a function of changes in volume rather than pricing. In 2011, approximately 46% of segment revenue was derived from U.S. land market areas (up from 35% in 2010), while approximately 25% of segment revenue was from the Gulf of Mexico market area (down from 32% in 2010) and approximately 29% of segment revenue was from international market areas (down from 33% in 2010). Three drilling products and their ancillary equipment (accommodations, drill pipe and stabilization tools) each accounted for more than 20% of this segment s revenue in 2011.

The marine segment is comprised of our 18 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. With all of our liftboats currently operating in the Gulf of Mexico, our activity levels can be impacted by harsh weather, especially tropical systems that occur during hurricane season. We entered into an agreement on February 22, 2012 to sell our marine segment. We expect this transaction to close in March of 2012.

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 and intensity 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.

Historical market indicators are listed below:

	2011	% Change	2010	% Change	2009
Worldwide Rig Count [1]					
U.S.	1,879	22%	1,546	42%	1,089
International [2]	1,167	7%	1,094	10%	997
Commodity Prices (average)					
Crude Oil (West Texas Intermediate)	$ 95.47	19%	$ 80.12	28%	$ 62.74
Natural Gas (Henry Hub)	$ 4.09	-8%	$ 4.44	3%	$ 4.29

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

(2) Excludes Canadian Rig Count.

As indicated by the table above, the major activity drivers continued to improve in 2011. The average number of drilling rigs working in the United States increased 22%, while the international rig count increased 7%. The average price of West Texas Intermediate crude oil increased 19% while the average price of Henry Hub natural gas decreased 8% from 2010.

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The following table compares our revenues generated from major geographic regions for the years ended December 31, 2011 and 2010 (in thousands). We attribute revenue to countries based on the location where services are performed or the destination of the sale of products.

	Revenue				
	2011	%	2010	%	Change
Gulf of Mexico	$ 669,166	32%	$ 675,836	40%	$ (6,670)
U.S. Land	856,130	42%	540,459	32%	315,671
International	544,870	26%	465,321	28%	79,549
Total	$ 2,070,166	100%	$ 1,681,616	100%	$ 388,550

In 2011, our U.S. land revenue increased 58% to $856.1 million as a result of higher oil prices, the increase in drilling rig counts (particularly the number of rigs drilling horizontal wells in the U.S. land market areas) and higher overall industry activity which led to increased utilization of existing assets and high utilization of new assets added through capital expenditures. In this market area, we experienced a 53% increase in revenue from our subsea and well enhancement segment and a 71% increase in revenue from our drilling products and services segment. Within individual product and service lines, the largest increases in the U.S. land market area were in coiled tubing, cased hole wireline, pressure control tools, rentals of accommodations and rentals and sales of premium drill pipe and accessories.

Our Gulf of Mexico revenue declined 1% to $669.2 million. The slow recovery in activity following the Deepwater Horizon incident in April 2010 without the offsetting spill recovery work that we concluded in the fourth quarter of 2010 resulted in a slight decline in our Gulf of Mexico revenue. Drilling and production activity was slow to recover through most of 2011 due to the slow pace of permits issued for such projects early in the year. While the incident curtailed much activity in the second half of 2010, the incident also created demand for many of our products and services during the well capping and cleanup phases, which were completed in the fourth quarter of 2010.

Our international revenue increased 17% to $554.9 million due primarily to improved performance at Hallin, increases in demand for completion tools, and down-hole drilling products and hydraulic workover and snubbing services in Latin America.

Industry Outlook

We believe drivers of industry demand, commodity prices and drilling rig counts should remain favorable in most geographic market areas. We also believe Gulf of Mexico deep water activity will continue to gradually increase. We believe U.S. land market areas with high concentrations of rigs drilling horizontal oil wells will remain underserved for products and services such as coiled tubing, premium drill pipe and ancillary products. Internationally, we expect to continue to build out market areas, such as Australia and Brazil, that provide us the best opportunities to provide as many products and services as possible. We expect our 2012 capital expenditures allocated for expansion in the U.S. land and international market areas will substantially increase over 2011 levels.

Our Gulf of Mexico operations generally focus on three areas: drilling support, production enhancement and decommissioning (or end of life) services. Our exposure to drilling activity is primarily in the drilling products and services segment. We anticipate that our financial performance from the Gulf of Mexico in this segment will gradually increase as the number of permits for deep water drilling increases, resulting in more rigs drilling in 2012 than 2011. In the shallow water Gulf of Mexico, most of our revenue is related to production enhancement and end of life services. We anticipate that demand for products and services participating in these market segments will remain stable.

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 of our consolidated financial statements, which is included in Part II, Item 8 of this Annual Report, contains a description of the significant 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, goodwill, income taxes, allowance for doubtful accounts, revenue recognition, long-term construction accounting, self insurance, and oil and gas properties. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances. Actual amounts could differ significantly from these estimates under different assumptions and conditions.

We define a critical accounting policy or estimate as one that is both important to 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 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.

As a result of pursuing strategic alternatives, we entered into an agreement dated February 22, 2012 to sell our marine segment. As such, we concluded that indicators of impairment existed and therefore conducted a fair value assessment of our liftboats at December 31, 2011. This valuation included two components: estimated undiscounted cash flows and indicated valuation evidenced by tenders from prospective buyers. We then applied a weighted average to the two components to obtain an estimate of the fair market value of the liftboats. Based on this valuation analysis, we determined that the liftboats had a fair market value that was approximately $35.8 million less than their carrying value. Therefore, a reduction in the value of assets (property, plant and equipment) was recorded for approximately $35.8 million.

Goodwill. In assessing the recoverability of goodwill, we 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 authoritative guidance related to goodwill and other intangibles, which 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.

We completed our assessment as of December 31, 2011 to determine whether our goodwill was impaired, and as a result we determined that it was more likely than not that the fair value of our marine segment was less than its carrying amount, indicating that goodwill was potentially impaired. As a result, we initiated the second step of the goodwill impairment test which involved calculating the implied fair value of our goodwill by allocating the fair value of the marine segment to all of the assets and liabilities other than goodwill and comparing it to the carrying amount of goodwill. We determined that the implied fair value of our goodwill for our marine segment was less than its carrying value and wrote-off the segment s goodwill balance of $10.3 million, which was recorded as a reduction in the value of assets. Based on business conditions and market values that existed at December 31, 2011, we concluded that no goodwill impairment was required in our subsea and well enhancement and drilling and product services segments.

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 collectability 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 title to the equipment has transferred to the customer.

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 the authoritative guidance related to 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.

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. 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 of this Annual Report).

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 obtain actuarial reviews to evaluate the reasonableness of internal estimates for losses related to workers compensation and group medical on an annual basis. Our financial results could be impacted if litigation trends, claims settlement patterns and future inflation rates are different from our estimates.

Oil and Gas Properties. Our subsidiary, Wild Well Control Inc. (Wild Well), and our equity-method investment, Dynamic Offshore Holding, LP (Dynamic Offshore), have oil and gas properties and the related well abandonment and decommissioning liabilities. Each of these entities follows the successful efforts method of accounting for their investment in oil and gas properties. Under the successful efforts method, the costs of successful exploratory wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip developmental wells, including unsuccessful developmental wells, are capitalized. Other costs such as geological and geophysical costs and the drilling costs of unsuccessful exploratory wells are expensed. All capitalized costs are accumulated and recorded separately for each field and allocated to leasehold costs and well costs. Leasehold costs and well costs are depleted on a units-of-production basis based on the estimated remaining equivalent proved developed oil and gas reserves of the field.

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

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

Proved Reserve Estimates. Our reserve information is prepared by independent reserve engineers in accordance with guidelines established by the Securities and Exchange Commission. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control such as

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commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. In accordance with the Securities and Exchange Commission s guidelines, we use twelve month average prices, year end costs and a 10% discount rate to determine the present value of future net cash flow. Actual prices and costs may vary significantly, and the discount rate may or may not be appropriate based on outside economic conditions.

Comparison of the Results of Operations for the Years Ended December 31, 2011 and 2010

For the year ended December 31, 2011, our revenue was $2,070.2 million and our net income was $142.6 million, or $1.76 diluted earnings per share. Included in the results for the year ended December 31, 2011 were non-cash pre-tax charges of $46.1 million for the reduction in value of assets within our marine segment. For the year ended December 31, 2010, our revenue was $1,681.6 million and our net income was $81.8 million, or $1.03 diluted earnings per share. Included in the results for the year ended December 31, 2010 were pre-tax management transition expenses of approximately $35.0 million, as well as non-cash pre-tax charges of $32.0 million for the reduction in value of assets within our marine segment.

The following table compares our operating results for the years ended December 31, 2011 and 2010 (in thousands). Cost of services, rentals and sales excludes depreciation, depletion, amortization and accretion for each of our business segments.

	Revenue			Cost of Services, Rentals and Sales				
	2011	2010	Change	2011	%	2010	%	Change
Subsea and Well Enhancement	$ 1,367,834	$ 1,112,662	$ 255,172	$ 832,568	61%	$ 675,447	61%	$ 157,121
Drilling Products and Services	611,101	474,707	136,394	220,647	36%	176,453	37%	44,194
Marine	91,231	94,247	(3,016)	64,788	71%	66,813	71%	(2,025)
Total	$ 2,070,166	$ 1,681,616	$ 388,550	$ 1,118,003	54%	$ 918,713	55%	$ 199,290

The following discussion analyzes our results on a segment basis.

Subsea and Well Enhancement Segment

Revenue for our subsea and well enhancement segment was $1,367.8 million for the year ended December 31, 2011, as compared to $1,112.7 million for 2010. Cost of services remained constant at 61% of segment revenue in both 2011 and 2010. Our increase in revenue and profitability is due to demand increases in the U.S. land and international market areas. Revenue from our U.S. land market area increased approximately 53% due to demand for coiled tubing, cased hole wireline, well control and pressure pumping services, as well as hydraulic workover and snubbing services. Additionally, revenue from our international market areas increased approximately 24% primarily due increased revenue from our subsea projects, well control services, hydraulic workover and snubbing services and our acquisition of Superior Completion Services in August of 2010. Revenue from our Gulf of Mexico market area decreased approximately 3% primarily based on a decline in revenue from work associated with our large-scale decommissioning project as well as a decrease in well control services. The decrease in the Gulf of Mexico was partially offset by increased revenue from cased hole wireline services, hydraulic snubbing and workover services and the acquisition of Superior Completion Services in 2010.

Drilling Products and Services Segment

Revenue for our drilling products and services segment was $611.1 million for the year ended December 31, 2011, an approximate 29% increase from 2010. Cost of services decreased slightly to 36% of segment revenue in

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2011 from 37% in 2010. The increase in revenue for this segment is primarily related to rentals of our accommodation units, drill pipe and specialty tubulars, specifically in our U.S. land market area. Revenue in our U.S. land market area increased approximately 71% for the year ended December 31, 2011 over the same period in 2010. Revenue generated from our international market areas increased approximately 12% for the year ended December 31, 2011 over the same period in 2010. This increase was primarily related to increased rentals of drill pipe and specialty tubulars. Revenue from our Gulf of Mexico market area remained essentially flat due to the lingering effects of the Macondo oil spill in April 2010.

Marine Segment

Our marine segment revenue for the year ended December 31, 2011 decreased approximately 3% from 2010 to $91.2 million. Our cost of services percentage remained constant at 71% of segment revenue for the years ended December 31, 2011 and 2010. Due to the high fixed cost nature of this segment, cost of services does not fluctuate proportionately with revenue. The fleet s average utilization decreased to approximately 66% in 2011 from 67% in 2010. However, the fleet s average dayrate increased to approximately $16,300 in 2011 from $13,600 in 2010. This is primarily due to the fact that our two 265 foot-class vessels, which typically generate our highest day rates, returned to work in the fourth quarter of 2010 after being taken out of service for repairs in the fourth quarter of 2009. During 2011, we sold seven of our smaller liftboats for $22.8 million and recorded gains of approximately $8.6 million. In December 2010, we also sold one of our 175-foot class liftboats for $5.4 million and recorded a gain of approximately $1.1 million.

On February 22, 2012, we entered into an agreement to sell the assets comprising our marine segment, or 18 liftboats. We expect this transaction to close in March of 2012.

Depreciation, Depletion, Amortization and Accretion

Depreciation, depletion, amortization and accretion increased to $257.3 million for the year ended December 31, 2011 from $220.8 million in 2010. Depreciation, depletion, amortization and accretion expense related to our subsea and well enhancement segment increased $20.3 million, or 21%, in 2011 from the same period in 2010. Increases in depreciation, depletion, amortization and accretion are related to the acquisition of Superior Completion Services, capital expenditures and increased utilization of subsea vessels. Depreciation and amortization expense increased within our drilling products and services segment by $16.1 million, or 14%, due to capital expenditures. Depreciation expense related to the marine segment remained constant for the years ended December 31, 2011 and 2010.

General and Administrative Expenses

General and administrative expenses increased to $383.6 million for the year ended December 31, 2011 from $342.9 million in 2010, which included approximately $35.0 million of management transition expenses. Increases in general and administrative expenses are attributable to the acquisition of Superior Completion Services and increased bonus and compensation expense due to our improved performance as well as additional infrastructure to enhance our growth.

Reduction in Value of Assets

As a result of pursuing strategic alternatives, we entered into an agreement on February 22, 2012 to sell our marine segment. As such, we recorded a reduction in the value of assets for approximately $46.1 million which included a write down of property and equipment of approximately $35.8 million and a write down of goodwill of approximately $10.3 million.

During 2010, we recorded a reduction in the value of assets totaling $32.0 million in connection with liftboat components primarily related to two partially completed liftboats. After a detailed evaluation, we concluded in December 2010 that it was impractical to complete these vessels. As such, we reduced our carrying value in these assets to their respective net realizable value.

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Comparison of the Results of Operations for the Years Ended December 31, 2010 and 2009

For the year ended December 31, 2010, our revenue was $1,681.6 million and our net income was $81.8 million, or $1.03 diluted earnings per share. Included in the results for the year ended December 31, 2010 were pre-tax management transition expenses of approximately $35.0 million, as well as non-cash pre-tax charges of $32.0 million for the reduction in value of assets within our marine segment. 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 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.

The following table compares our operating results for the years ended December 31, 2010 and 2009 (in thousands). Cost of services, rentals and sales excludes depreciation, depletion, amortization and accretion for each of our business segments.

	Revenue			Cost of Services, Rentals and Sales				
	2010	2009	Change	2010	%	2009	%	Change
Subsea and Well Enhancement	$ 1,112,662	$ 919,335	$ 193,327	$ 675,447	61%	$ 616,116	67%	$ 59,331
Drilling Products and Services	474,707	426,876	47,831	176,453	37%	143,802	34%	32,651
Marine	94,247	103,089	(8,842)	66,813	71%	64,116	62%	2,697
Total	$ 1,681,616	$ 1,449,300	$ 232,316	$ 918,713	55%	$ 824,034	57%	$ 94,679

The following discussion analyzes our results on a segment basis.

Subsea and Well Enhancement Segment

Revenue for our subsea and well enhancement segment was $1,112.7 million for the year ended December 31, 2010, as compared to $919.3 million for 2009. Our increase in revenue and profitability is primarily due to demand increases in the U.S. land and international market areas. Revenue from our U.S. land market area increased approximately 75% due to demand for coiled tubing, cased hole wireline, well control services and hydraulic workover and snubbing services. Additionally, revenue from our international market areas increased approximately 77% primarily due to our acquisition of Hallin along with increased revenue from our well control services and hydraulic workover and snubbing services. Revenue from our Gulf of Mexico market area decreased approximately 18% primarily based on a decline in revenue from work associated with our large-scale decommissioning project. This decrease was partially offset by increased well control work and plug and abandonment activity, as well as our acquisitions of Superior Completion Services and the Bullwinkle platform.

Cost of services decreased to 61% of segment revenue in 2010, as compared to 67% of segment revenue in 2009. Similar to revenue, our profitability increased due to increased demand for coiled tubing, cased hole wireline, well control services and hydraulic workover and snubbing services. Additionally, cost of services as a percentage of revenue for 2009 was impacted due to the adjustment related to our large-scale decommissioning 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 was recognized in the period in which revisions were identified.

Drilling Products and Services Segment

Revenue for our drilling products and services segment was $474.7 million for the year ended December 31, 2010, an approximate 11% increase from 2009. Cost of services increased to 37% of segment revenue in 2010 from 34% in 2009. The increase in revenue for this segment is primarily related to rentals of our accommodation units and specialty tubulars, specifically in our U.S. land market area. Revenue in our U.S. land market area increased approximately 54% for the year ended December 31, 2010 over the same period in 2009. Revenue generated from our international market areas increased approximately 5%. Revenue from our Gulf of Mexico market area decreased approximately 11% due to decreased demand for specialty tubulars and stabilization equipment as a result of the lingering effects of the deepwater drilling moratorium. The decrease in demand for specialty tubulars was partially offset by an increase in demand for accommodation rentals, which benefited from oil spill cleanup efforts. Cost of services as a percentage of revenue increased 4% as rentals from high-margin drill pipe, specialty tubulars and stabilization equipment fell significantly in the Gulf of Mexico due to the deepwater drilling moratorium.

Marine Segment

Our marine segment revenue for the year ended December 31, 2010 decreased 9% from 2009 to $94.3 million. Our cost of services percentage increased to 71% of segment revenue for the year ended December 31, 2010 from 62% in 2009 primarily due to increased liftboat inspections and maintenance costs coupled with decreased revenue. Due to the high fixed cost nature of this segment, cost of services does not fluctuate proportionately with revenue. The fleet s average utilization increased to approximately 67% in 2010 from 52% in 2009. However, the fleet s average dayrate decreased to approximately $13,600 in 2010 from $16,800 in 2009. The average dayrate decreased as several of our larger liftboats were not available for work due to inspections and repairs. Both of our 250-foot class liftboats were out of service for an extended period of time for U.S. Coast Guard inspections. Additionally, our two completed 265-foot class liftboats returned to service in October and November of 2010 after being out of service for repairs since November 2009. In December 2010, we also sold one of our 175-foot class liftboats for $5.4 million and recorded a gain of approximately $1.1 million.

Depreciation, Depletion, Amortization and Accretion

Depreciation, depletion, amortization and accretion increased to $220.8 million for the year ended December 31, 2010 from $207.1 million in 2009. Depreciation, depletion, amortization and accretion expense related to our subsea and well enhancement segment increased $5.3 million, or 6%, in 2010 from the same period in 2009. Increases in depreciation, depletion, amortization and accretion related to the acquisitions of Superior Completion Services, Hallin and the Bullwinkle platform, along with 2009 and 2010 capital expenditures, were offset by the decrease in depreciation and amortization as a result of the $212.5 million reduction in value of assets related to our U.S. land market area recorded in 2009. Depreciation and amortization expense increased within our drilling products and services segment by $9.1 million, or 9%, due to 2009 and 2010 capital expenditures. Depreciation expense related to the marine segment decreased $0.7 million, or 6%. The decrease in depreciation expense in our marine segment is attributable to very low utilization of our larger boats as our 250-foot class liftboats were out of service for an extended period of time for U.S. Coast Guard inspections and our two completed 265-foot class liftboats returned to service in the October and November of 2010 after being out of the service for repairs since November 2009.

General and Administrative Expenses

General and administrative expenses increased to $342.9 million for the year ended December 31, 2010 from $259.1 million in 2009. Included in this increase is approximately $35.0 million of management transition expenses. Additional increases in general and administrative expenses include the acquisitions of Superior Completion Services and Hallin, as well as increased bonus and compensation expense due to our improved performance, and additional infrastructure to enhance our growth.

Reduction in Value of Assets

During 2010, we recorded a reduction in the value of assets totaling $32.0 million in connection with liftboat components primarily related to our two partially completed class liftboats. After a detailed evaluation, we concluded in December that it was impractical to complete these vessels. As such, we reduced our carrying value in these assets to their respective net realizable value.

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 was primarily due to the decline in demand for services in the U.S. land market area. During the fourth quarter of 2009, the U.S. land market area 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 in 2009, 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.

Liquidity and Capital Resources

In the year ended December 31, 2011, we generated net cash from operating activities of $492.8 million as compared to $456.0 million in 2010. Our primary liquidity needs are for working capital and to fund capital expenditures, debt service and acquisitions. Our primary sources of liquidity are cash flows from operations and available borrowings under our revolving credit facility. We had cash and cash equivalents of $80.3 million at December 31, 2011 compared to $50.7 million at December 31, 2010. In addition, we had restricted cash and cash equivalents of approximately $785.3 million that was used to partially fund the Complete acquisition. At December 31, 2011, approximately $46.6 million of our cash balance was held in foreign jurisdictions. Cash balances held in foreign jurisdictions could be repatriated to the United States; however, they would be subject to United States federal income taxes, less applicable foreign tax credits. The Company has not provided United States income tax expense on earnings of its foreign subsidiaries because it expects to reinvest the undistributed earnings indefinitely.

We expect increased liquidity in 2012 from Complete s cash on hand at the date of acquisition. In addition, we collected $45.5 million, exclusive of selling costs, in February 2012 from the sale of a derrick barge. We also expect to collect $134.0 million, exclusive of working capital and selling costs, from the pending sale of our marine segment in the first quarter of 2012 and $129.7 million late in the first half of 2012 in connection with the large-scale platform decommissioning project in the Gulf of Mexico, pending certain regulatory approvals. These amounts are exclusive of any tax payments related to these transactions.

We spent $484.6 million of cash on capital expenditures during the year ended December 31, 2011. Approximately $200.9 million was used to expand and maintain our drilling products and services equipment inventory, approximately $2.5 million was spent on our marine segment and approximately $281.2 million was used to expand and maintain the asset base of our subsea and well enhancement segment.

At December 31, 2011, we had a $400 million bank revolving credit facility. Any amounts outstanding under the revolving credit facility were due on July 20, 2014. At December 31, 2011, we had $75.0 million outstanding under the bank credit facility with a weighted average interest rate of 5.0% per annum. On February 7, 2012, at the time of the Complete acquisition, we amended our revolving credit facility to increase the borrowing capacity to $600 million from $400 million, and to include a $400 million term loan. The maturity date for both the credit facility and the term loan is February 7, 2017, and any amounts outstanding under the revolving credit facility and the term loan are due at maturity. The principal balance of the term loan is payable in installments of $5.0 million on the last day of each fiscal quarter, commencing June 30, 2012. At February 17, 2012, we had $211.0 million outstanding under the bank credit facility with a weighted average interest rate of 3.6% per annum. We also had $33.3 million of letters of credit outstanding, which reduces our borrowing capacity under this credit facility. Borrowings under the credit facility bear interest at LIBOR 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.

At December 31, 2011, we had outstanding $12.5 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 (MARAD), for two 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 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. We have notified MARAD of our intent to repay this facility in connection with the sale of our marine segment.

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.

In April 2011, we issued $500 million of 6 3/8% unsecured senior notes due 2019. The indenture governing the 6 3/8% senior notes requires semi-annual interest payments on May 1st and November 1st of each year through the maturity date of May 1, 2019. 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 used a portion of the net proceeds of this offering, together with borrowings under our revolving credit facility to redeem, on December 15, 2011, all of our outstanding $400 million 1.50% senior exchangeable notes.

In December 2011, we issued $800 million of 7 1/8% unsecured senior notes due 2021. The indenture governing the 7 1/8% senior notes requires semi-annual interest payments on June 15th and December 15th of each year through the maturity date of December 15, 2021. 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 used proceeds from this offering to partially fund the Complete acquisition.

Our current long-term issuer credit rating is BB+ by Standard and Poor s (S&P) and Ba2 by Moody s. S&P recently revised its outlook on our company to positive from stable, as well as affirmed their BB+ corporate credit rating. S&P s positive outlook reflects their expectation that we will enhance operating momentum with the Complete acquisition.

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The following table summarizes our contractual cash obligations and commercial commitments at December 31, 2011 (amounts in thousands). We do not have any other material obligations or commitments.

Description	2012	2013	2014	2015	2016	Thereafter
Long-term debt, including estimated interest payments	$ 116,582	$ 114,804	$ 477,773	$ 90,324	$ 90,272	$ 1,676,195
Capital lease obligations, including estimated interest payments	6,225	6,225	6,225	6,225	6,225	12,969
Decommissioning liabilities, undiscounted	10,552	5,276	8,793	5,276	5,276	129,069
Operating leases	14,493	10,785	8,095	4,608	2,918	17,743
Vessel construction	44,750					
Other long-term liabilities		22,868	9,588	9,445	8,097	30,778
Total	$ 192,602	$ 159,958	$ 510,474	$ 115,878	$ 112,788	$ 1,866,754

We currently believe that we will spend approximately $1.1 billion to $1.2 billion on capital expenditures, excluding acquisitions, during 2012. We believe that our current working capital, cash generated from our operations, cash generated from dispositions and availability under our revolving credit facility will provide sufficient funds for our identified capital projects.

In May 2010, we signed a contract for construction of a compact semi-submersible vessel. This vessel is designed for both shallow and deepwater conditions and will be capable of performing subsea construction, inspection, repairs and maintenance work, as well as subsea light well intervention and abandonment work. The vessel is expected to be delivered in the first half of 2013.

We intend to continue implementing our growth strategy of increasing our scope of services through both internal growth and strategic acquisitions. We expect to continue to make the capital expenditures required to implement our growth strategy in amounts consistent with the amount of cash generated from operating activities, cash proceeds from dispositions, 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 potential additional consideration that may be payable as a result of the future operating performances of an acquisition and a guarantee on the performance of certain decommissioning liabilities. We do not have any other financing arrangements that are not required under generally accepted accounting principles to be reflected in our financial statements.

At December 31, 2011, the maximum additional consideration payable for an acquisition was approximately $3.0 million. Since this acquisition occurred before we adopted the revised authoritative guidance for 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. During the year ended December 31, 2011, we paid additional consideration of approximately $1.2 million as a result of prior acquisitions.

In connection with the sale of SPN Resources in 2008, we guaranteed the performance of its decommissioning liabilities. In accordance with authoritative guidance related to guarantees, we have assigned an estimated value of $2.6 million at December 31, 2011 and 2010 related to decommissioning performance guarantees, which is reflected in other long-term liabilities. We believe that the likelihood of being required to perform these guarantees is remote. In the unlikely event that Dynamic Offshore defaults on the decommissioning liabilities, the total maximum potential obligation under these guarantees is estimated to be approximately $158.7 million, net of the contractual right to receive payments from third parties, which is approximately $24.6 million, as of December 31, 2011. The total maximum potential obligation will decrease over time as the underlying obligations are fulfilled by SPN Resources.

Hedging Activities

In an attempt to achieve a more balanced debt portfolio, we entered into an interest rate swap in March 2010 whereby we are entitled to receive semi-annual interest payments at a fixed rate of 6 7/8% per annum and are obligated to make quarterly interest payments at a variable rate. Interest rate swap agreements that are effective at hedging the fair value of fixed-rate debt agreements are designated and accounted for as fair value hedges. At December 31, 2011, we had fixed-rate interest on approximately 87% of our long-term debt. As of December 31, 2011, we had a notional amount of $150 million related to this interest rate swap with a variable interest rate, which is adjusted every 90 days, based on LIBOR plus a fixed margin.

From time to time, we may enter into forward foreign exchange contracts to hedge the impact of foreign currency fluctuations. We do not enter into forward foreign exchange contracts for trading purposes. During the years ended December 31, 2011 and 2009, we did not hold any foreign currency forward contracts. During the year ended December 31, 2010, we held foreign currency forward contracts outstanding in order to hedge exposure to currency fluctuations. These contracts are not designated as hedges and are marked to fair market value each period. As of December 31, 2011, we had no outstanding foreign currency forward contracts.

Recently Issued Accounting Pronouncements

See Part II, Item 8, Financial Statements and Supplementary Data Note 1 Summary of Significant Accounting Policies Recently Issued Accounting Pronouncements.

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 certain 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.

We do not hold derivatives for trading purposes or use derivatives with complex features. Assets and liabilities of certain subsidiaries in the United Kingdom and Europe are translated at end of period 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 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, 2011, we had no outstanding foreign currency forward contracts.

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Interest Rates

At December 31, 2011, our debt (exclusive of discounts), was comprised of the following (in thousands):

	Fixed Rate Debt	Variable Rate Debt
Bank revolving credit facility due 2014 ^	$	$ 75,000
6.875% Senior notes due 2014 *	150,000	150,000
6.375% Senior notes due 2019	500,000	
7.125% Senior notes due 2021	800,000	
U.S. Government guaranteed long-term financing due 2027	12,546	
Total Debt	$ 1,462,546	$ 225,000

(^) Upon the consummation of the Complete acquisition, we amended our revolving credit facility to increase the borrowing capacity to $600 million from $400 million and added a $400 million term loan. Additionally, the amendment extended the maturity date to February 7, 2017.

(*) In March 2010, we entered into an interest rate swap agreement for a notional amount of $150 million, whereby we are entitled to receive semi-annual interest payments at a fixed rate of 6 7/8% per annum and are obligated to make quarterly interest payments at a variable rate. The variable interest rate, which is adjusted every 90 days, is based on LIBOR plus a fixed margin.

Based on the amount of this debt outstanding at December 31, 2011, a 10% increase in the variable interest rate would increase our interest expense for the year ended December 31, 2011 by approximately $1.2 million, while a 10% decrease would decrease our interest expense by approximately $1.2 million.

Commodity Price Risk

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

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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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, 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.

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, 2011, 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 28, 2012 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

KPMG LLP

New Orleans, Louisiana

February 28, 2012

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidated Balance Sheets

December 31, 2011 and 2010

(in thousands, except share data)

	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 80,274	$ 50,727
Accounts receivable, net of allowance for doubtful accounts of $17,484 and $22,618 at December 31, 2011 and 2010, respectively	540,602	452,450
Prepaid expenses	34,037	25,828
Inventory and other current assets	228,309	235,047
Total current assets	883,222	764,052
Property, plant and equipment, net	1,507,368	1,313,150
Goodwill	581,379	588,000
Notes receivable	73,568	69,026
Equity-method investments	72,472	59,322
Intangible and other long-term assets, net	930,136	113,983
Total assets	$ 4,048,145	$ 2,907,533
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 178,645	$ 110,276
Accrued expenses	197,574	162,044
Income taxes payable	717	2,475
Deferred income taxes	831	29,353
Current portion of decommissioning liabilities	14,956	16,929
Current maturities of long-term debt	810	184,810
Total current liabilities	393,533	505,887
Deferred income taxes	297,458	223,936
Decommissioning liabilities	108,220	100,787
Long-term debt, net	1,685,087	681,635
Other long-term liabilities	110,248	114,737
Stockholders equity:		
Preferred stock of $0.01 par value. Authorized, 5,000,000 shares; none issued		
Common stock of $0.001 par value. Authorized, 125,000,000 shares; issued and outstanding 80,425,443 and 78,951,053 shares at December 31, 2011 and 2010, respectively	80	79
Additional paid in capital	447,007	415,278
Accumulated other comprehensive loss, net	(26,936)	(25,700)
Retained earnings	1,033,448	890,894
Total stockholders equity	1,453,599	1,280,551
Total liabilities and stockholders equity	$ 4,048,145	$ 2,907,533

See accompanying notes to consolidated financial statements.

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidated Statements of Operations

Years Ended December 31, 2011, 2010 and 2009

(in thousands, except per share data)

	2011	2010	2009
Revenues	$ 2,070,166	$ 1,681,616	$ 1,449,300
Costs and expenses:			
Cost of services (exclusive of items shown separately below)	1,118,003	918,713	824,034
Depreciation, depletion, amortization and accretion	257,313	220,835	207,114
General and administrative expenses	383,567	342,881	259,093
Reduction in value of assets	46,096	32,004	212,527
Gain on sale of businesses	8,558	1,083	2,084
Income (loss) from operations	273,745	168,266	(51,384)
Other income (expense):			
Interest expense, net of amounts capitalized	(73,843)	(57,377)	(50,906)
Interest income	6,226	5,143	926
Other income (expense)	(822)	825	571
Earnings (losses) from equity-method investments, net	16,394	8,245	(22,600)
Reduction in value of equity-method investment			(36,486)
Income (loss) before income taxes	221,700	125,102	(159,879)
Income taxes	79,146	43,285	(57,556)
Net income (loss)	$ 142,554	$ 81,817	$ (102,323)
Basic earnings (loss) per share	$ 1.79	$ 1.04	$ (1.31)
Diluted earnings (loss) per share	$ 1.76	$ 1.03	$ (1.31)
Weighted average common shares used in computing earnings per share:			
Basic	79,654	78,758	78,171
Incremental common shares from stock options	1,271	840	
Incremental common shares from restricted stock units	170	136	
Diluted	81,095	79,734	78,171

See accompanying notes to consolidated financial statements.

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidated Statements of Changes in Stockholders Equity

Years Ended December 31, 2011, 2010 and 2009

(in thousands, except share data)

Consolidated Statements of Changes in Stockholders Equity

	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 (loss):								
Net loss							(102,323)	(102,323)
Other comprehensive income (loss) 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 income (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 unit			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
Comprehensive income (loss):								
Net income							81,817	81,817
Other comprehensive loss Foreign currency translation adjustment						(6,704)		(6,704)
Total comprehensive income (loss)						(6,704)	81,817	75,113
Grant of restricted stock units					950			950
Restricted stock grant and compensation expense, net of forfeitures			342,694		11,367			11,367
Exercise of stock options			87,150		927			927
Tax benefit from exercise of stock options					560			560
Stock option compensation expense					15,493			15,493
Shares issued to pay performance share unit								
Shares issued under Employee Stock Purchase Plan			94,250		2,233			2,233
Shares withheld and retired			(132,391)		(4,137)			(4,137)

Balances, December 31, 2010	$	78,951,053	$	79	$ 415,278	$	(25,700)	$	890,894	$ 1,280,551

See accompanying notes to consolidated financial statements.

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidated Statements of Changes in Stockholders Equity (Continued)

Years Ended December 31, 2011, 2010 and 2009

(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, 2010		$	78,951,053	$ 79	$ 415,278	$ (25,700)	$ 890,894	$ 1,280,551
Comprehensive income (loss):								
Net income							142,554	142,554
Other comprehensive loss Foreign currency translation adjustment						(1,236)		(1,236)
Total comprehensive income (loss)						(1,236)	142,554	141,318
Grant of restricted stock units					1,140			1,140
Restricted stock grant and compensation expense, net of forfeitures			541,425		5,996			5,996
Exercise of stock options			876,435	1	10,262			10,263
Tax benefit from exercise of stock options					9,004			9,004
Stock option compensation expense					3,348			3,348
Shares issued to pay performance share units			67,288		2,759			2,759
Shares issued under Employee Stock Purchase Plan			75,745		2,594			2,594
Share issuance cost					(335)			(335)
Shares withheld and retired			(86,503)		(3,039)			(3,039)
Balances, December 31, 2011		$	80,425,443	$ 80	$ 447,007	$ (26,936)	$ 1,033,448	$ 1,453,599

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, 2011, 2010 and 2009

(in thousands)

	2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ 142,554	$ 81,817	$ (102,323)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	257,313	220,835	207,114
Deferred income taxes	48,073	8,276	(74,704)
Excess tax benefit from stock-based compensation	(9,004)	(560)	(170)
Reduction in value of assets	46,096	32,004	212,527
Reduction in value of equity-method investments			36,486
Stock based and performance share unit compensation expense	14,032	27,207	11,785
Retirement and deferred compensation plans expense	1,990	4,825	1,550
(Earnings) losses from equity-method investments, net of cash received	(13,152)	2,905	28,606
Amortization of debt acquisition costs and note discount	25,178	23,954	21,744
Gain on sale of businesses	(8,558)	(1,083)	(2,084)
Other reconciling items, net	(6,426)	(4,708)	
Changes in operating assets and liabilities, net of acquisitions and dispositions:			
Accounts receivable	(86,814)	(89,800)	25,609
Inventory and other current assets	2,182	85,687	(51,320)
Accounts payable	40,289	20,303	(24,637)
Accrued expenses	24,961	14,754	(41,264)
Decommissioning liabilities	(504)	(1,759)	
Income taxes	(1,378)	10,510	(2,301)
Other, net	15,972	20,806	29,485
Net cash provided by operating activities	492,804	455,973	276,103
Cash flows from investing activities:			
Payments for capital expenditures	(484,648)	(323,244)	(286,277)
Acquisitions of businesses, net of cash acquired	(1,748)	(276,077)	(1,247)
Proceeds from sale of businesses	22,349	5,250	7,716
Change in restricted cash held for acquisition of a business	(785,280)		
Purchase of short-term investments	(223,491)		
Proceeds from sale of short-term investments	223,630		
Cash contributed to equity-method investment			(8,694)
Other	(721)	(9,402)	(3,769)
Net cash used in investing activities	(1,249,909)	(603,473)	(292,271)
Cash flows from financing activities:			
Net (payments) borrowings from revolving line of credit	(100,000)	(2,000)	177,000
Proceeds from issuance of long-term debt	1,300,000		
Principal payments of long-term debt	(400,810)	(810)	(810)
Payment of debt issuance costs	(24,428)	(5,182)	(2,308)
Proceeds from exercise of stock options	10,263	927	375
Excess tax benefit from stock-based compensation	9,004	560	170
Proceeds from issuance of stock through employee benefit plans	2,206	1,891	1,958
Other	(9,662)	(3,443)	

Net cash provided by (used in) financing activities	786,573	(8,057)	176,385
Effect of exchange rate changes on cash	79	(221)	1,435
Net increase (decrease) in cash and cash equivalents	29,547	(155,778)	161,652
Cash and cash equivalents at beginning of year	50,727	206,505	44,853
Cash and cash equivalents at end of year	$ 80,274	$ 50,727	$ 206,505

See accompanying notes to consolidated financial statements.

SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements

December 31, 2011, 2010 and 2009

(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 2011 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 products and services 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 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 2011 and 2010, no single customer accounted for more than 10% of total revenue. In 2009 Chevron accounted for approximately 15%, Apache accounted for approximately 13% and BP accounted for approximately 11% of total revenue, primarily related to our subsea and well enhancement segment.

In addition to trade receivables, other financial instruments that potentially subject the Company to concentrations of credit risk consist of cash and derivative instruments used in hedging activities. The Company periodically evaluates the creditworthiness of financial institutions that may serve as a counterparty. The financial institutions in which the Company transacts business are large, investment grade financial institutions which are well-capitalized under applicable regulatory capital adequacy guidelines, thereby minimizing its exposure to credit risks for deposits in excess of federally insured amounts and for failure to perform as the counterparty on interest rate swap agreements.

(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) Inventory and Other Current Assets

Inventories are stated at the lower of cost or market. Cost is determined using the first-in, first-out (FIFO) or weighted-average cost methods for finished goods and work-in-process. Supplies and consumables consist principally of products used in our services provided to customers.

Inventory and other current assets include approximately $83.1 million and $70.0 million of inventory at December 31, 2011 and 2010, respectively. Our inventory balance at December 31, 2011 consisted of approximately $39.0 million of finished goods, $2.3 million of work-in-process, $5.4 million of raw materials and $36.4 million of supplies and consumables. Our inventory balance at December 31, 2010 consisted of $31.4 million of finished goods, $1.4 million of work-in-process, $2.2 million of raw materials and $35.0 million of supplies and consumables.

Additionally, inventory and other current assets include approximately $133.4 million and $146.9 million of costs incurred and estimated earnings in excess of billings on uncompleted contracts at December 31, 2011 and 2010, respectively. The Company follows the percentage-of-completion method of accounting for applicable contracts.

(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 larger marine vessels, 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 5 years
Furniture and fixtures	2 to 10 years

The Company s larger marine vessels 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 occurs primarily through use rather than through the passage of time.

The Company follows the successful efforts method of accounting for its investment in oil and natural gas properties. Under the successful efforts method, the costs of successful exploratory wells and leases containing productive reserves are capitalized. Costs incurred to drill and equip developmental wells, including unsuccessful development wells, are capitalized. Other costs such as geological and

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geophysical costs and the drilling costs of unsuccessful exploratory wells expensed. Leasehold and well costs are depleted on a units-of-production basis based on the estimated remaining equivalent proved oil and gas reserves of each field.

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 $7.1 million, $2.7 million and $2.9 million in 2011, 2010 and 2009, respectively, of interest for various capital projects.

In accordance with authoritative guidance on 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. 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. 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.

As a result of pursuing strategic alternatives, the Company entered into an agreement dated February 22, 2012 to sell its marine segment. As such, the Company concluded that indicators of impairment existed and therefore conducted a fair value assessment of the liftboats at December 31, 2011. This valuation included two components: estimated undiscounted cash flows and indicated valuation evidenced by tenders from prospective buyers. A weighted average was applied to the two components to obtain an estimate of the fair market value of the liftboats. Based on this valuation analysis, the Company determined that the liftboats had a fair market value that was approximately $35.8 million less than their carrying value. Therefore, a reduction in the value of assets (property, plant and equipment) was recorded for approximately $35.8 million.

For the year ended December 31, 2010, the Company recorded a reduction in the value of assets totaling $32.0 million in connection with liftboat components primarily related to the two partially completed liftboats. For the year ended December 31, 2009, the Company recorded approximately $119.8 million reduction in the value of assets, related to property, plant and equipment, due to the decline in the U.S. land market area.

(i) Goodwill

In accordance with authoritative guidance on intangible assets, goodwill is 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 standalone 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. No impairment loss was recognized during the years ended December 31, 2010 and 2009, as the fair value of the reporting unit exceeded the carrying amount. A significant amount of judgment was involved in performing these evaluations since the results are based on estimated future events.

The Company completed its assessment at December 31, 2011 to determine whether goodwill was impaired and as a result determined that it was more likely than not that the fair value of the marine segment was less than its carrying amount, indicating that goodwill was potentially impaired. As a result, the Company initiated the second step of the goodwill impairment test which involved calculating the implied fair value of the goodwill by allocating the fair value of the marine segment to all of the assets and liabilities other than goodwill and comparing it to the carrying amount of goodwill. The Company determined that the implied fair value of the goodwill for the marine segment was less than its carrying value and fully wrote-off the goodwill balance of $10.3 million, which was recorded as a reduction in the value of assets.

The following table summarizes the activity for the Company s goodwill for the years ended December 31, 2011 and 2010 (amounts in thousands):

	Subsea and Well Enhancement	Drilling Products and Services	Marine	Total
Balance, December 31, 2009	$ 332,111	$ 139,436	$ 10,933	$ 482,480
Acquisition activities	93,650			93,650
Disposition activities			(80)	(80)
Additional consideration paid for prior acquisitions	14,029	1,000		15,029
Foreign currency translation adjustment	(2,106)	(973)		(3,079)
Balance, December 31, 2010	$ 437,684	$ 139,463	$ 10,853	$ 588,000
Acquisition activities	3,563			3,563
Disposition activities			(519)	(519)
Reduction in value of asset			(10,334)	(10,334)
Additional consideration paid for prior acquisitions		1,000		1,000
Foreign currency translation adjustment	(296)	(35)		(331)
Balance, December 31, 2011	$ 440,951	$ 140,428	$	$ 581,379

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.

(j) Notes Receivable

Notes receivable consist of a commitment from the seller of oil and gas properties towards the abandonment of the acquired property. Pursuant to an agreement with the seller, the Company will invoice the seller an agreed upon amount at the completion of certain decommissioning activities. The gross amount of this note totaled $115.0 million and is recorded at present value using an effective interest rate of 6.58%. The related discount is amortized to interest income based on the expected timing of the platform s removal. The Company recorded interest income related to notes receivable of $4.5 million for each of the years ended December 31, 2011 and 2010.

(k) Intangible and Other Long-Term Assets

Intangible and other long-term assets consist of the following at December 31, 2011 and 2010 (amounts in thousands):

	December 31, 2011			December 31, 2010		
	Gross Amount	Accumulated Amortization	Net Balance	Gross Amount	Accumulated Amortization	Net Balance
Customer relationships	$ 23,707	$ (6,144)	$ 17,563	$ 23,306	$ (4,317)	$ 18,989
Tradenames	18,005	(2,706)	15,299	17,924	(1,622)	16,302
Non-compete agreements	1,697	(1,126)	571	1,320	(1,211)	109
Debt issuance costs	41,449	(10,039)	31,410	25,886	(14,412)	11,474
Deferred compensation plan assets	10,598		10,598	10,820		10,820
Escrowed cash	50,196		50,196	33,013		33,013
Restricted cash and cash equivalents	785,280		785,280			
Long-term assets held as major replacement spares	13,806		13,806	19,999		19,999
Other	6,018	(605)	5,413	3,780	(503)	3,277
Total	$ 950,756	$ (20,620)	$ 930,136	$ 136,048	$ (22,065)	$ 113,983

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 13 years, 17 years, and 3 years, respectively. Debt issuance costs are amortized primarily using the effective interest method over the life of the related debt agreements with a weighted average useful life of 9 years. Amortization of debt issuance costs is recorded in interest expense. Amortization expense (exclusive of debt issuance costs) was approximately $3.4 million, $3.3 million and $4.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. Estimated annual amortization of intangible assets (exclusive of debt acquisition costs) will be approximately $3.4 million for 2012, $3.3 million for 2013, $3.2 million for 2014, $3.0 million for 2015 and $2.9 million for 2016, excluding the effects of any acquisitions or dispositions subsequent to December 31, 2011.

In connection with the issuance of the Company s $800 million of 7 1/8% unsecured senior notes due 2021, certain restrictions were placed on the proceeds from the issuance of these notes. These restrictions limit the Company to use the proceeds, net of fees and expenses from the issuance, for the acquisition of Complete Production Services, Inc. (NYSE: CPX) (Complete). At December 31, 2011, the Company held $785.3 million in other long-term assets as net proceeds from the issuance of these notes (see note 8), which were used to partially fund the acquisition of Complete on February 7, 2012.

As a result of the annual review for impairment of long-lived assets in accordance with authoritative guidance, the Company recorded approximately $92.7 million as a reduction in the value of intangible assets during the year ended December 31, 2009.

(l) Decommissioning Liabilities

The Company records estimated future decommissioning liabilities in accordance with the authoritative guidance related to asset retirement obligations (decommissioning liabilities), which requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, with a corresponding increase in the carrying amount of the related long-lived asset. Subsequent to initial measurement, the decommissioning liability is required to be accreted each period to present value. The Company s decommissioning liabilities associated with the Bullwinkle platform and its related assets consist of costs related to the plugging of wells, the removal of the related facilities and equipment, and site restoration.

Whenever practical, the Company utilizes its own equipment and labor services to perform well abandonment and decommissioning work. When the Company performs these services, all recorded intercompany revenues and related costs of services are eliminated in the consolidated financial statements. The recorded decommissioning liability associated with a specific property is fully extinguished when the property is abandoned. The recorded liability is first reduced by all cash expenses incurred to abandon and decommission the property. If the recorded liability exceeds (or is less than) the Company s total costs, then the difference is reported as income (or loss) within revenue during the period in which the work is performed. The Company reviews the adequacy of its decommissioning liabilities whenever indicators suggest that the estimated cash flows needed to satisfy the liability have changed materially. The Company reviews its estimates for the timing of these expenditures on a quarterly basis.

In connection with the acquisition of Superior Completion Services in 2010, the Company assumed approximately $10.0 million of decommissioning liabilities associated with restoring two chartered vessels to the original condition in which they were received.

The following table summarizes the activity for the Company s decommissioning liabilities for the years ended December 31, 2011 and 2010 (amounts in thousands):

	2011	2010
Decommissioning liabilities, December 31, 2010 and 2009, respectively	$ 117,716	$
Liabilities acquired and incurred		136,559
Liabilities settled	(504)	(1,759)
Accretion	6,752	7,018
Revision in estimated liabilities	(788)	(24,102)
Total decommissioning liabilities, December 31, 2011and 2010, respectively	123,176	117,716
Less: current portion of decommissioning liabilities at December 31, 2011 and 2010, respectively	14,956	16,929
Long-term decommissioning liabilities, December 31, 2011 and 2010, respectively	$ 108,220	$ 100,787

(m) Revenue Recognition

Products and services are generally sold based upon purchase orders or contracts with customers that include fixed or determinable prices. Revenue is recognized when services or equipment are provided and collectability is reasonably assured. The Company contracts for marine and 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 billed on a day rate basis, and revenue from the sale of equipment is recognized when the title to the equipment has been transferred. 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 accounted 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). The Company recognizes oil and gas revenue from its interests in producing wells as oil and natural gas is sold.

(n) Taxes Collected from Customers

In accordance with authoritative guidance related to 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.

(o) 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 and rates that are in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on the deferred income taxes is recognized in income in the period in which the change occurs. A valuation allowance is recorded when management believes it is more likely than not that at least some portion of any deferred tax asset will not be realized.

The Company has adopted authoritative guidance surrounding accounting for uncertainty in income taxes. It is the Company s policy to recognize interest and applicable penalties related to uncertain tax positions in income tax expense.

(p) Earnings (Loss) per Share

Basic earnings (loss) per share is computed by dividing net 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 using the treasury stock method.

Stock options and restricted stock units for approximately 540,000, 1,650,000 and 1,180,000 shares were excluded in the computation of diluted earnings per share for the years ended December 31, 2011, 2010 and 2009, respectively, as the effect would have been anti-dilutive.

(q) Fair Value Measurements

The Company follows authoritative guidance for fair value measurements relating to financial and nonfinancial assets and liabilities, including presentation of required disclosures herein. This guidance 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; and

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

(r) Financial Instruments

The fair value of the Company s financial instruments of cash equivalents, accounts receivable, accounts payable, accrued expenses and revolving credit facility approximates their carrying amounts due to their short maturity or market interest rates. The fair value of the Company s debt was approximately $1,749.8 million and $902.5 million at December 31, 2011 and 2010, 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.

(s) 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 international 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 date 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. For the years ended December 31, 2011, 2010 and 2009 the Company recorded approximately $1.4 million, $1.6 million and $3.5 million of foreign currency gains, respectively.

(t) Stock-Based Compensation

In accordance with authoritative guidance related to stock compensation, the Company records compensation costs relating to share -based payment transactions and includes such costs in general and administrative expenses in the statement of operations. 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). Excess tax benefits of awards that are recognized in equity related to stock option exercises and restricted stock vesting are reflected as financing cash flows.

(u) Derivative Instruments and Hedging Activities

The Company recognizes all derivative instruments as either assets or liabilities in the balance sheet at their respective fair values. Interest rate swap agreements that are effective at hedging the fair value of fixed-rate debt agreements are designated and accounted for as fair value hedges. The Company also assesses, both at inception of the hedging relationship and on an ongoing basis, whether the derivatives used in hedging relationships are highly effective in offsetting changes in fair value.

In an attempt to achieve a more balanced debt portfolio, the Company entered into an interest rate swap in March 2010. Under this agreement, the Company is entitled to receive semi-annual interest payments at a fixed rate of 6 7/8% per annum and is obligated to make quarterly interest payments at a variable rate. At December 31, 2011, the Company had fixed-rate interest on approximately 87% of its long-term debt. As of December 31, 2011, the Company had a notional amount of $150 million related to this interest rate swap with a variable interest rate, which is adjusted every 90 days, based on LIBOR plus a fixed margin.

From time to time, the Company may enter into forward foreign exchange contracts to hedge the impact of foreign currency fluctuations. The Company does not enter into forward foreign exchange contracts for trading purposes. During the years ended December 31, 2011 and 2009, the Company did not hold any foreign currency forward contracts. During the year ended December 31, 2010, the Company held foreign currency forward contracts outstanding in order to hedge exposure to currency fluctuations. These contracts are not designated as hedges, for hedge accounting treatment, and were marked to fair market value each period and changes in fair value were recognized in earnings.

(v) Other Comprehensive Loss

The following table reconciles the change in accumulated other comprehensive loss for the years ended December 31, 2011 and 2010 (amounts in thousands):

	2011	2010
Accumulated other comprehensive loss, net, December 31, 2010 and 2009, respectively	$ (25,700)	$ (18,996)
Other comprehensive loss, net of tax: Foreign currency translation adjustment	(1,236)	(6,704)
Accumulated other comprehensive loss, net, December 31, 2011 and 2010, respectively	$ (26,936)	$ (25,700)

(w) Equity Method Investments

Investments in entities that are not controlled by the Company, but where the Company has the ability to exercise significant 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 consolidated statements of operations.

(x) Self Insurance Reserves

The Company is self insured, through deductibles and retentions, up to certain levels for losses related to workers compensation, third party liability insurances, property damage, and group medical. With the Company s growth, the Company has elected to retain more risk by increasing its self insurance. The Company accrues for these liabilities based on estimates of the ultimate cost of claims incurred as of the balance sheet date. The Company regularly reviews the estimates of reported and unreported claims and provides for losses through reserves. The Company obtains actuarial reviews to evaluate the reasonableness of internal estimates for losses related to workers compensation and group medical on an annual basis.

(y) Subsequent Events

In accordance with authoritative guidance, the Company has evaluated and disclosed all material subsequent events that occurred after the balance sheet date, but before financial statements were issued.

(z) Recently Issued Accounting Pronouncements

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Presentation of Comprehensive Income (ASU 2011-05). The amendments in ASU 2011-05 allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both instances, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive

income. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders equity. The amendments in ASU 2011-05 do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. However, in December 2011, the FASB issued Accounting Standards Update No. 2011-12, Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (ASU 2011-12), which deferred the guidance on whether to require entities to present reclassification adjustments out of accumulated other comprehensive income by component in both the statement where net income is presented and the statement where other comprehensive income is presented for both interim and annual financial statements. ASU 2011-12 reinstated the requirements for the presentation of reclassifications that were in place prior to the issuance of ASU 2011-05 and did not change the effective date for ASU 2011-05. For public entities, the amendments in ASU 2011-05 and ASU 2011-12 are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, and should be applied retrospectively. The adoption of this guidance will change the Company s financial statement presentation of comprehensive income but will not impact the consolidated financial position or results of operations.

In September 2011, the FASB issued ASU No. 2011-08, Intangibles Goodwill and Other (ASU 2011-08). ASU 2011-08 allows a qualitative assessment of whether it is more likely than not that a reporting unit s fair value is less than its carrying amount before applying the two-step goodwill impairment test. If it is more likely than not that the fair value of a reporting unit is less than its carrying amount, then the two-step impairment test would be performed. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, and early adoption is permitted. This update changed the process the Company used to test goodwill for impairment, but did not have a material impact on its consolidated financial statements.

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). This newly issued accounting standard requires an entity to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this accounting standard only requires enhanced disclosure, the adoption of this standard is not expected to have an impact on our consolidated financial position or results of operations.

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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, 2011, 2010 and 2009 (amounts in thousands):

	2011	2010	2009
Cash paid for interest, net of amounts capitalized	$ 39,539	$ 34,034	$ 28,833
Cash paid for income taxes	$ 22,320	$ 25,435	$ 16,434
Details of business acquisitions:			
Fair value of assets	$ 8,650	$ 515,767	$ 1,247
Fair value of liabilities	(6,902)	(228,417)	
Cash paid	1,748	287,350	1,247
Less cash acquired		(11,273)	
Net cash paid for acquisitions	$ 1,748	$ 276,077	$ 1,247
Details of proceeds from sale of businesses:			
Book value of assets	$ 13,791	$ 4,236	$ 5,632
Book value of liabilities		81	
Receivable due from sale		(150)	
Gain on sale of business	8,558	1,083	2,084
Proceeds from sale of businesses	$ 22,349	$ 5,250	$ 7,716
Non-cash investing activity:			
Long term payable on vessel construction	$	$	$ 5,000
Capital expenditures included in accounts payable	$ 23,053	$	$
Additional consideration payable on acquisitions	$	$	$ 484
Non-cash financing activity:			
Share settlement for employee tax liability	$	$ 3,093	$

(3) Acquisitions

In September 2011, the Company acquired 100% of the equity interest in a pressure pumping company based in Brazil in order to expand the breadth of services offered in Brazil. The Company paid approximately $0.5 million at closing, with an additional $5.8 million payable after the settlement of certain liabilities and administrative formalities. Identifiable intangible assets include goodwill of $3.6 million, all of which was assigned to the Company s subsea and well enhancement segment.

In August 2010, the Company acquired certain assets (operating as Superior Completion Services) from subsidiaries of Baker Hughes Incorporated (Baker Hughes) for approximately $54.3 million. The assets purchased were used in Baker Hughes Gulf of Mexico stimulation and sand control business.

In January 2010, the Company acquired 100% of the equity interest of Hallin Marine Subsea International Plc (Hallin) for approximately $162.3 million. Additionally, the Company repaid approximately $55.5 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, Indonesia, Australia, Scotland and the United States.

In January 2010, Wild Well Control, Inc. (Wild Well), a wholly-owned subsidiary of the Company, acquired 100% ownership of Shell Offshore, Inc. s Gulf of Mexico Bullwinkle platform and its related assets and assumed the related decommissioning obligation. Immediately after Wild Well acquired these assets, it conveyed an undivided 49% interest in these assets and the related well plugging and abandonment obligations to Dynamic Offshore Holding, LP (Dynamic Offshore), which operates these assets. Additionally, Dynamic Offshore will pay Wild Well to extinguish its 49% portion of the well plugging and abandonment obligation (see note 5).

The Company has an off-balance sheet financing arrangement for additional consideration that may be payable as a result of the future operating performance of an acquisition. At December 31, 2011, the maximum additional contingent consideration payable was approximately $3.0 million and will be determined and payable through 2012. Since this acquisition occurred before the Company adopted the revised authoritative guidance for business combinations, 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 paid additional consideration of approximately $1.2 million for the year ended December 31, 2011, as a result of prior acquisitions. Of the consideration paid, $1.0 million was capitalized during the year ended December 31, 2011 and $0.2 million had been capitalized and accrued during 2010.

Subsequent Event

On February 7, 2012, the Company acquired Complete Production Services, Inc. (Complete) pursuant to a merger that substantially expanded the size and scope of the Company. The total consideration for this acquisition approximates $2,917.9 million, which includes both cash and stock. Complete stockholders received 0.945 of a share of the Company s common stock and $7.00 cash for each share of Complete s common stock outstanding at the time of the acquisition. In total, the Company paid approximately $553.9 million in cash and issued approximately 75.5 million shares valued at approximately $2,310.7 million (based on the closing price of the Company s common stock on the acquisition date of $30.90). Additionally, the Company will repay $650.0 million of Complete s debt.

During the year ended December 31, 2011, the Company expensed approximately $4.5 million of acquisition related costs, which was recorded in general and administrative expenses. The Company expects to incur approximately $23.0 million of additional acquisition related costs in the first quarter of 2012 related to this acquisition.

Complete focuses on providing specialized completion and production services and products that help oil and gas companies develop hydrocarbon reserves, reduce costs and enhance production. Complete s operations are located throughout the United States and Mexico. Management believes that the acquisition will position the combined company as the only mid-cap oilfield service company in the United States (a company with market capitalization between $3 billion and $10 billion) providing services and equipment to upstream oil and natural gas operators, making the combined company better equipped to compete with the larger oilfield service companies and to expand internationally. Complete will be reported under the subsea and well enhancement segment.

The Company funded the Complete acquisition with $800 million of 7 1/8% unsecured senior notes due 2021 which were issued in December 2011, a $400 million term loan facility and by increasing the capacity of the Company s revolving credit facility from $400 million to $600 million (see note 8).

The transaction will be accounted for using the acquisition method of accounting which requires that, among other things, assets acquired and liabilities assumed be recorded at their fair values as of the acquisition date. The excess of the consideration transferred over those fair values is recorded as goodwill. None of the goodwill related to this acquisition will be deductible for tax purposes. As the initial valuation and subsequent purchase accounting for this acquisition is incomplete due to the timing of the acquisition, the Company is unable to provide the allocation of the aggregate purchase price for each major class of assets acquired and liabilities assumed. Since the pro forma statement of earnings data is dependent on the purchase price allocation, the Company is also unable to provide pro forma information for the year ending December 31, 2011 at this time. These disclosures will be included in our interim consolidated financial statements for the period ending March 31, 2012.

(4) Dispositions

During 2011, the Company sold seven liftboats for approximately $22.3 million, net of commissions, resulting in a pre-tax gain of approximately $8.6 million for the year ended December 31, 2011. In December 2010, the Company sold one liftboat for approximately $5.4 million, inclusive of a $0.1 million receivable, resulting in a pre-tax gain of approximately $1.1 million for the year ended December 31, 2010. In 2009, the Company sold four liftboats for approximately $7.7 million resulting in a pre-tax gain of approximately $2.1 million for the year ended December 31, 2009.

Subsequent Events

On February 15, 2012, the Company sold a derrick barge to a marine construction company based in India. The Company received proceeds of $44.3 million, inclusive of selling costs. The carrying value of the derrick barge and related assets approximated $37.9 million, exclusive of $9.7 million of goodwill. The Company expects to record a pre-tax loss of approximately $3.3 million in the first quarter of 2012 in connection with this sale. The operations of this derrick barge have been reported under the Subsea and Well Enhancement Segment.

On February 22, 2012, the Company entered into an agreement to sell the assets comprising its marine segment, or 18 liftboats. The Company is expected to receive cash proceeds of approximately $134 million, exclusive of working capital and selling costs, which approximates the segment s carrying value at December 31, 2011. At December 31, 2011, the Company had outstanding $12.5 million in U.S. Government guaranteed long-term financing, which is administered by the Maritime Administration, for two liftboats. The Company has notified the Maritime Administration of its intent to repay this facility in connection with the sale of its marine segment. The Company expects to record an additional pre-tax loss at the time of sale for various expenses, including commissions, separation agreements and losses on the extinguishment of debt. The sale of these assets will constitute all of the marine segment as defined in the segment disclosure (see note 11). The Company expects this transaction to close in March of 2012.

(5) Long-Term Contracts

In January 2010, Wild Well acquired 100% ownership of Shell Offshore Inc. s Gulf of Mexico Bullwinkle platform and its related assets, and assumed the decommissioning obligations of such assets. In connection with the conveyance of an undivided 49% interest in these assets and the related well plugging and abandonment obligations, Dynamic Offshore will pay Wild Well to extinguish its portion of the well plugging and abandonment obligations, limited to the current fair value of the obligation at the time of acquisition. As part of the asset purchase agreement with Shell Offshore Inc., Wild Well was required to obtain a $50 million performance bond as well as fund $50 million into an escrow account. Included in intangible and other long-term assets, net is escrowed cash of $50.2 million and $33.0 million as of December 31, 2011 and 2010, respectively. Included in other long-term liabilities is deferred revenue of $24.6 million and $16.2 million as of December 31, 2011 and 2010, respectively.

In December 2007, 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. As of December 31, 2011, the work on this project was substantially complete, pending certain regulatory approvals. The revenue related to the contract for decommissioning these downed platforms and wells was recorded on the percentage-of-completion method utilizing costs incurred as a percentage of total estimated costs. Included in other current assets at December 31, 2011 and 2010 is approximately $129.7 million and $144.5 million, respectively, of costs and estimated earnings in excess of billings related to this contract.

(6) Property, Plant and Equipment

A summary of property, plant and equipment at December 31, 2011 and 2010 (in thousands) is as follows:

	2011	2010
Buildings, improvements and leasehold improvements	$ 139,432	$ 127,725
Marine vessels and equipment	417,413	499,398
Machinery and equipment	1,596,580	1,248,318
Automobiles, trucks, tractors and trailers	38,770	31,934
Furniture and fixtures	40,575	35,124
Construction-in-progress	171,108	83,694
Land	29,518	24,223
Oil and gas producing assets	44,109	34,336
	2,477,505	2,084,752
Accumulated depreciation and depletion	(970,137)	(771,602)
Property, plant and equipment, net	$ 1,507,368	$ 1,313,150

In connection with the review for impairment of long-lived assets in accordance with authoritative guidance, the Company recorded approximately $35.8 million as a reduction in the value of property, plant and equipment during the year ended December 31, 2011 as the indicated valuation from prospective buyers was less than the carrying value of certain marine assets. During 2010, the Company recorded a reduction in the value of assets totaling $32.0 million in connection with liftboat components primarily related to the partially completed liftboats. During 2009, 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 primarily related to assets servicing the U.S. land market area.

The Company had approximately $23.2 million and $22.7 million of leasehold improvements at December 31, 2011 and 2010, respectively. These leasehold improvements are depreciated over the shorter of the life of the asset or the term of the lease using the straight line method. Depreciation expense (excluding depletion, amortization and accretion) was approximately $224.6 million, $207.7 million, $202.8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Capital Lease

Hallin is the lessee of a dynamically positioned subsea vessel under a capital lease expiring in 2019 with a 2 year renewal option. Hallin owns a 5% equity interest in the entity that owns this leased asset. The entity owning this vessel had $28.9 million of debt as of December 31, 2011, all of which was non-recourse to the Company. The amount of the asset and liability under this capital lease is recorded at the present value of the lease payments. This vessel is depreciated using the units-of-production method based on the utilization of the vessel and is subject to a minimum amount of annual depreciation. The units-of-production method is used for this vessel because depreciation occurs primarily through use rather than through the passage of time. The vessel s gross asset value under the capital lease was approximately $37.6 million at inception and depreciation expense was approximately $4.2 million for the year ending December 31, 2011 and $3.8 million from the date of acquisition through December 31, 2010. At December 31, 2011 and 2010, the Company had approximately $29.5 million and $33.0 million, respectively, included in other long-term liabilities, and approximately $3.6 million and $3.2 million, respectively, included in accounts payable related to the obligations under this capital lease. The future minimum lease payments under this capital lease are approximately $3.6 million, $3.9 million, $4.2 million, $4.6 million and $5.0 million in the years ending December 31, 2012, 2013, 2014, 2015 and 2016 respectively, exclusive of interest at an annual rate of 8.5%. For each of the years ended December 31, 2011 and 2010, the Company recorded interest expense of approximately $3.0 million in connection with this capital lease.

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(7) Equity-Method Investments

In March 2011, the Company contributed all of its equity interests in SPN Resources and DBH, LLC (DBH) to Dynamic Offshore, the majority owner of both SPN Resources and DBH, in exchange for a 10% limited partnership interest in Dynamic Offshore. Following these contributions, Dynamic Offshore owns all the equity interests of SPN Resources and DBH. Prior to these contributions, the Company accounted for its equity interests in SPN Resources and DBH as separate equity-method investments. The Company s equity interest in Dynamic Offshore is accounted for as an equity-method investment with a balance of approximately $70.6 million at December 31, 2011. The Company recorded income from its equity-method investment in Dynamic Offshore of approximately $15.0 million for the ten months ended December 31, 2011 following the contributions. Additionally, the Company received approximately $2.8 million of cash distributions from its equity-method investment in Dynamic Offshore for the ten month period ended December 31, 2011. The Company, where possible and at competitive rates, provides its products and services to assist Dynamic Offshore in producing and developing its oil and gas properties. The Company had a receivable from Dynamic Offshore of approximately $9.8 million at December 31, 2011. The Company also recorded revenue from Dynamic Offshore of approximately $44.9 million for the ten months ended December 31, 2011 following the contributions. Additionally, the Company has a receivable from Dynamic Offshore of approximately $14.0 million as of December 31, 2011 related to its share of oil and natural gas commodity sales and production handling arrangement fees.

The Company s equity-method investment balance in SPN Resources was approximately $43.6 million at December 31, 2010. The Company recorded earnings from its equity-method investment in SPN Resources of approximately $0.2 million for the two months ended February 28, 2011 prior to the contributions and approximately $1.2 million for the year ended December 31, 2010. The Company recorded losses from this equity-method investment of approximately $7.6 million for the year ended December 31, 2009. Additionally, the Company received approximately $9.9 million and $5.9 million, respectively, of cash distributions from its equity-method investment in SPN Resources for the years ended December 31, 2010 and 2009. 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 SPN Resources of approximately $3.2 million at December 31, 2010. The Company also recorded revenue from SPN Resources of approximately $0.3 million for the two months ended February 28, 2011 and approximately $11.4 million and $11.0 million, respectively, for the years ended December 31, 2010 and 2009. 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.

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 recorded a loss from its equity-method investment in BOG of approximately $14.0 million for the year ended December 31, 2009. The Company also recorded revenue of approximately $7.0 million from BOG for the year ended December 31, 2009. The Company also recorded a decrease in its investment in BOG of approximately $6.1 million for the year ended December 31, 2009 for its proportionate share of accumulated other comprehensive income generated from hedging transactions. The Company recorded a net increase in revenue and its investment in BOG for services provided by the Company that were capitalized by BOG of approximately $0.2 million for the year ended December 31, 2009.

In October 2009, 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. DBH s purchase of BOG using the acquisition method of accounting resulted in a difference between the carrying amount of the Company s investment in DBH and the underlying equity in net assets. The difference is being adjusted against the equity in earnings based on the depletion of DBH s oil and gas assets and related reserves. The Company s equity-method investment balance in DBH was approximately $13.8 million at December 31, 2010. The Company recorded earnings from its equity-method investment in DBH of approximately $0.9 million for the two months ended February 28, 2011 prior to the contributions and $7.1 million for the year ended December 31, 2010. 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. Additionally, the Company received approximately $1.0 million of cash distributions from its equity-method investment in DBH for the year ended December 31, 2010. The Company had a receivable from this equity-method investment of approximately $1.4 million at December 31, 2010. The Company also recorded revenue from this equity-method investment of approximately $0.9 million for the two months ended February 28, 2011 prior to the contributions and $4.1 million for the year ended December 31, 2010. From the date of acquisition through December 31, 2009, the Company recorded revenue from this equity-method investment of $2.4 million.

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

	December 31, 2011	December 31, 2010
Current Assets	$ 229,516	$ 104,241
Noncurrent assets	1,305,514	487,136
Total assets	$ 1,535,030	$ 591,377
Current liabilities	$ 202,465	$ 49,587
Noncurrent liabilities	797,031	197,672
Total liabilities	$ 999,496	$ 247,259

	Years Ended December 31, 2011	2010	2009
Revenues	$ 468,140	$ 204,935	$ 245,092
Cost of sales	181,433	80,525	110,101
Gross profit	$ 286,707	$ 124,410	$ 134,991
Income (loss) from continuing operations	$ 95,581	$ (8,016)	$ (10,024)

Subsequent Event

On February 1, 2012, SandRidge Energy Inc. (NYSE: SD) entered into an agreement to acquire Dynamic Offshore for aggregate consideration of $1.275 billion consisting of approximately $680 million in cash and approximately 74 million shares of SandRidge common stock valued at an assumed price of $8.02 per share. This sale is expected to close in the second quarter of 2012, at which time the anticipated gain will be reflected. In accordance with authoritative guidance related to equity securities, the Company will account for the shares received through this transaction as available-for-sale securities. The shares will be recorded at their fair market value and any unrealized gains or losses will be excluded from earnings and reported as a net amount within accumulated other comprehensive income (loss) within stockholders equity.

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(8) Debt

The Company s long-term debt as of December 31, 2011 and 2010 consisted of the following (in thousands):

	2011	2010
Revolving credit facility interest payable monthly at floating rate, due December 2014	$ 75,000	$ 175,000
U.S. Government guaranteed long-term financing interest payable semiannually at 6.45%, due in semiannual installments through June 2027	12,546	13,356
Senior Notes interest payable semiannually at 6 7/8%, due June 2014	300,000	300,000
Discount on 6 7/8% Senior Notes	(1,649)	(2,248)
Senior Notes interest payable semiannually at 6 3/8%, due May 2019	500,000	
Senior Notes interest payable semiannually at 7 1/8%, due December 2021	800,000	
Senior Exchangeable Notes interest payable semiannually at 1.5% until December 2011 and 1.25% thereafter		400,000
Discount on 1.5% Senior Exchangeable Notes		(19,663)
	1,685,897	866,445
Less current portion	810	184,810
Long-term debt	$ 1,685,087	$ 681,635

The Company had a $400 million bank revolving credit facility. Any amounts outstanding under the revolving credit facility were due on July 20, 2014. The weighted average interest rate on amounts outstanding under the revolving credit facility was 5.0% and 3.4% per annum at December 31, 2011 and 2010, respectively. On February 7, 2012, this revolving credit facility was amended in connection with the Complete acquisition. See additional details on this amendment within the subsequent event portion of this footnote.

The Company also had approximately $11.0 million of letters of credit outstanding, which reduce the Company s borrowing availability under the revolving 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, 2011, the Company was in compliance with all such covenants.

At December 31, 2011, the Company had outstanding $12.5 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 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, 2011, the Company was in compliance with all such covenants. The Company has notified the Maritime Administration of its intent to repay this facility in connection with the sale of the marine segment.

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, 2011, the Company was in compliance with all such covenants.

In April 2011, the Company issued $500 million of 6 3/8% unsecured senior notes due 2019. Costs associated with the issuance of these notes were approximately $9.7 million and were capitalized and will be amortized over the term of the 6 3/8% senior notes. The Company used a portion of the proceeds of this debt issuance to redeem all of the outstanding $400 million 1.50% senior exchangeable notes on December 15, 2011. The indenture governing the 6 3/8% senior notes requires semi-annual interest payments on May 1st and November 1st of each year through the maturity date of May 1, 2019. 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, 2011, the Company was in compliance with all such covenants.

In December 2011, the Company issued $800 million of 7 1/8% unsecured senior notes due 2021. Costs associated with the issuance of these notes were approximately $15.1 million and were capitalized and will be amortized over the term of the notes. Certain restrictions were placed on the proceeds from the issuance of these notes. These restrictions limited the Company to use the proceeds, net of fees and expenses from the issuance, to partially fund the Complete acquisition which occurred in February 2012 (see note 3). The indenture governing the 7 1/8% senior notes requires semi-annual interest payments on June 15th and December 15th of each year through the maturity date of December 15, 2021. 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, 2011, the Company was in compliance with all such covenants.

On December 15, 2011, the Company redeemed all of its outstanding $400 million 1.50% senior exchangeable notes for 100% of the principal amount. As the holders of the Company s 1.50% senior exchangeable notes had the ability to require the Company to purchase all of the notes on December 15, 2011, the entire amount of these notes would have been deemed to be a current liability at December 31, 2010. However, in accordance with accounting guidance related to classification of short-term debt that is to be refinanced, the Company utilized the amount available to it under its revolving credit facility as of December 31, 2010 of approximately $216.0 million to classify this portion as long-term under the assumption that the revolving credit facility could be used to refinance that portion of the debt.

Annual maturities of long-term debt for each of the five fiscal years following December 31, 2011 and thereafter are as follows (in thousands):

2012	810
2013	810
2014	375,810
2015	810
2016	810
Thereafter	1,308,496
Total	$ 1,687,546

Subsequent Events

On February 7, 2012, in connection with the Complete acquisition, the Company amended its bank credit facility to increase the revolving borrowing capacity to an aggregate amount of $600 million from $400 million and to include a $400 million term loan. The maturity date of both the credit facility and the term loan is February 7, 2017, and any amounts outstanding under the revolving credit facility and the term loan are due at maturity. The principal balance of the term loan is payable in installments of $5.0 million on the last day of each fiscal quarter, commencing on June 30, 2012. Costs associated with these amendments totaled approximately $24.5 million. These costs will be capitalized and amortized over the term of the credit facility.

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(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 stock options generally vest in equal installments over three years and expire in ten years. Non-vested stock options are generally forfeitable upon termination of employment. During 2011, the Company granted 207,183 non-qualified stock options under these same terms.

In accordance with authoritative guidance related to stock-based compensation, 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 uses historical data, among other factors, to estimate the expected price volatility, the expected life of the stock option 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 stock option. The following table presents the fair value of stock option grants made during the years ended December 31, 2011, 2010 and 2009, and the related assumptions used to calculate the fair value:

	Years Ended December 31,		
	2011 Actual	2010 Actual	2009 Actual
Weighted average fair value of grants	$ 13.54	$ 10.56	$ 8.95
Black-Scholes-Merton Assumptions:			
Risk free interest rate	0.85%	2.07%	1.77%
Expected life (years)	5	4	4
Volatility	56.31%	49.28%	53.57%
Dividend yield			

The Company s compensation expense related to stock options for the years ended December 31, 2011, 2010 and 2009 was approximately $3.3 million, $15.5 million and $2.4 million, respectively, which is reflected in general and administrative expenses. During 2010, the Company modified 1,418,395 stock options, affecting three employees in connection with the management transition of certain executive officers. These stock options were accelerated to vest by December 31, 2010. The Company incurred incremental compensation cost of approximately $9.8 million during 2010 as a result of this modification.

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The following table summarizes stock option activity for the years ended December 31, 2011, 2010 and 2009:

	Number of Options	Weighted Average Option Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2008	3,267,910	$ 15.37		
Granted	309,352	$ 20.01		
Exercised	(38,717)	$ 9.71		
Outstanding at December 31, 2009	3,538,545	$ 15.84		
Granted	1,549,058	$ 25.04		
Exercised	(87,150)	$ 10.62		
Outstanding at December 31, 2010	5,000,453	$ 18.78		
Granted	207,183	$ 28.97		
Exercised	(876,435)	$ 11.71		
Outstanding at December 31, 2011	4,331,201	$ 20.70	6.0	$ 36,885
Exercisable at December 31, 2011	3,647,745	$ 19.62	5.4	$ 34,783
Options expected to vest	683,456	$ 26.46	8.9	$ 2,102

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, 2011 and the stock option price, multiplied by the number of in-the-money stock options) that would have been received by the stock option holders if all the options had been exercised on December 31, 2011. 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 stock options exercised during the year ended December 31, 2011 (the difference between the stock price upon exercise and the option price) was approximately $23.4 million. The Company received approximately $10.3 million, $0.9 million and $0.4 million during the years ended December 31, 2011, 2010 and 2009, respectively, from employee stock option exercises. In accordance with authoritative guidance related to stock-based compensation, the Company has reported the tax benefits of approximately $7.4 million, $0.6 million, $0.2 million from the exercise of stock options for the years ended December 31, 2011, 2010 and 2009, respectively, as financing cash flows.

A summary of information regarding stock options outstanding at December 31, 2011 is as follows:

Range of Exercise Prices	Options Outstanding: Shares	Options Outstanding: Weighted Average Remaining Contractual Life	Options Outstanding: Weighted Average Price	Options Exercisable: Shares	Options Exercisable: Weighted Average Price
$7.31 $8.79	61,665	1.3 years	$ 8.78	61,665	$ 8.78
$9.10 $9.90	80,313	0.4 years	$ 9.48	80,313	$ 9.48
$10.36 $10.90	770,268	2.6 years	$ 10.66	770,268	$ 10.66
$12.45 $13.34	309,977	6.9 years	$ 12.88	309,977	$ 12.88
$17.46 $23.00	1,502,669	6.3 years	$ 19.92	1,236,572	$ 19.55
$24.00 $30.00	1,133,657	7.9 years	$ 25.98	829,664	$ 25.38
$34.40 $37.64	464,239	6.8 years	$ 35.37	350,873	$ 35.57

$40.00	$40.69	8,413	6.2 years	$ 40.69	8,413	$ 40.69

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The following table summarizes non-vested stock option activity for the year ended December 31, 2011:

	Number of Options	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2010	869,971	$ 10.23
Granted	207,183	$ 13.54
Vested	(393,698)	$ 9.61
Non-vested at December 31, 2011	683,456	$ 11.59

As of December 31, 2011, there was approximately $6.8 million of unrecognized compensation expense related to non-vested stock options outstanding. The Company expects to recognize approximately $3.7 million, $2.2 million and $0.9 million of compensation expense during the years 2012, 2013 and 2014, respectively, for these outstanding non-vested stock options.

Restricted Stock

During the year ended December 31, 2011, the Company granted 567,083 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 forfeitable 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, 2011, 2010 and 2009 was approximately $6.0 million, $11.4 million and $5.8 million, respectively, which is reflected in general and administrative expenses. During 2010, the Company modified 282,781 shares of restricted stock affecting three employees in connection with the management transition of certain executive officers. These shares of restricted stock were accelerated to vest by December 31, 2010. The Company incurred incremental compensation cost of approximately $4.3 million during the year as a result of this modification.

A summary of the status of restricted stock for the year ended December 31, 2011 is presented in the table below:

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested at December 31, 2010	792,436	$ 22.25
Granted	567,083	$ 28.84
Vested	(294,144)	$ 19.80
Forfeited	(25,658)	$ 22.49
Non-vested at December 31, 2011	1,039,717	$ 27.07

As of December 31, 2011, there was approximately $21.8 million of unrecognized compensation expense related to non-vested restricted stock. The Company expects to recognize approximately $9.1 million, $7.4 million, $5.3 million during the years 2012, 2013 and 2014, respectively, for non-vested restricted stock. In accordance with authoritative guidance related to stock-based compensation, the Company has reported tax benefits of approximately $1.6 million from the vesting of restricted stock for the year ended December 31, 2011 as financing cash flows.

Restricted Stock Units

Under the Amended and Restated 2004 Directors Restricted Stock Units Plan, each non-employee director is issued annually a number of Restricted Stock Units (RSUs) having an aggregate dollar value determined by the Company s Board of Directors. The exact number of RSUs granted is determined by dividing the dollar value determined by the Company s Board of Directors based on 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. At December 31, 2011, 170,457 RSUs were outstanding under this plan. The Company s expense related to RSUs for the years ended December 31, 2011, 2010 and 2009 was approximately $1.2 million, $1.2 million and $0.6 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, 2011 is presented in the table below:

	Number of Restricted Stock Units	Weighted Average Grant Date Fair Value
Outstanding at December 31, 2010	136,173	$ 27.02
Granted	34,284	$ 35.10
Outstanding at December 31, 2011	170,457	$ 28.64

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, provided the participant has met specified continued service requirements. At December 31, 2011, there were 366,133 PSUs outstanding (70,522, 96,673, 81,154 and 117,784 related to performance periods ending December 31, 2011, 2012, 2013 and 2014, respectively). The Company s compensation expense related to all outstanding PSUs for the years ended December 31, 2011, 2010 and 2009 was approximately $3.2 million, $5.2 million and $7.3 million, respectively, which is reflected in general and administrative expenses. The Company has recorded a current liability of approximately $3.8 million and $6.0 million at December 31, 2011 and 2010, respectively, for outstanding PSUs, which is reflected in accrued expenses. Additionally, the Company has recorded a long-term liability of approximately $6.8 million and $7.0 million at December 31, 2011 and 2010, respectively, for outstanding PSUs, which is reflected in other long-term liabilities. In 2011, the Company paid approximately $2.8 million and issued approximately 67,300 shares of its common stock to settle PSUs for the performance period ended December 31, 2010. In 2010, the Company paid approximately $6.4 million in cash to settle PSUs for the performance period ended December 31, 2009. In 2009, the Company paid approximately $4.7 million in cash and issued approximately 71,400 shares of its common stock to its employees to settle PSUs for the performance period ended December 31, 2008.

Employee Stock Purchase Plan

The Company has an employee stock purchase plan under which an aggregate of 1,250,000 shares of common stock were reserved for issuance. Under this stock purchase plan, eligible employees can purchase shares of the Company s common stock at a discount. The Company received approximately $2.2 million, $1.9 million and $2.0 million related to shares issued under these plans for the years ended December 31, 2011, 2010 and 2009, respectively. For the years ended December 31, 2011, 2010 and 2009, the Company recorded compensation expense of approximately $388,000, $345,000 and $350,000, respectively, which is reflected in general and administrative expenses. Additionally, the Company issued approximately 75,700, 94,200 and 133,400 shares for the years ended December 31, 2011, 2010 and 2009, respectively, related to these stock purchase plans.

Profit Sharing Plan

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 plan subject to the contribution 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 $7.4 million, $3.3 million and $3.8 million in 2011, 2010 and 2009, respectively.

Non-Qualified Deferred Compensation Plan

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 balances. 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 14). At December 31, 2011 and 2010, the liability of the Company to the participants was approximately $13.0 million and $14.2 million, respectively, which reflects the accumulated participant deferrals and earnings (losses) as of that date. These amounts are recorded in other long-term liabilities. Additionally at December 31, 2011 and 2010, the Company had approximately $2.8 million and $3.0 million in accounts payable in anticipation of pending payments. For the years ended December 31, 2011, 2010 and 2009, the Company recorded compensation income (expense) of approximately $0.1 million, ($1.8) million and ($2.8) million, respectively, related to the earnings and losses of the deferred compensation plan liability. The Company makes contributions that approximate the participant deferrals into various investments, principally life insurance that is invested in mutual funds similar to the participants hypothetical investment elections. Changes in market value of the investments and life insurance are reflected as adjustments to the deferred compensation plan asset with an offset to other income (expense). At December 31, 2011 and 2010, the deferred contribution plan asset was approximately $10.6 million and $10.8 million, respectively, and is recorded in intangible and other long-term assets. For the years ended December 31, 2011, 2010 and 2009, the Company recorded other income (expense) of ($0.2) million, $0.8 million and $0.6 million, respectively, related to the earnings and losses of the deferred compensation plan assets.

Supplemental Executive Retirement Plan

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 2011, 2010 and 2009, the participants in the plan received contributions ranging from 5% to 35% of salary and annual cash bonus, which totaled approximately $1.0 million, $5.5 million and $2.2 million, respectively. The Company may also make discretionary contributions to a participant s retirement account. In 2010, the Company made a discretionary contribution to the account of its former chief operating officer in the amount of $4.7 million as part of its executive management transition. The Company recorded $1.8 million, $5.6 million and $2.1 million of compensation expense in general and administrative expenses for the years ended December 31, 2011, 2010 and 2009, respectively, inclusive of discretionary contributions. During the year ended December 31, 2011, the Company paid approximately $5.5 million to select participants of this plan. There were no payments to participants of this plan in the years 2010 and 2009.

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(10) Income Taxes

The components of income and loss from continuing operations before income taxes for the years ended December 31, 2011, 2010 and 2009 are as follows (in thousands):

	2011	2010	2009
Domestic	$ 220,908	$ 117,988	$ (191,543)
Foreign	792	7,114	31,664
	$ 221,700	$ 125,102	$ (159,879)

The components of income tax expense (benefit) for the years ended December 31, 2011, 2010 and 2009 are as follows (in thousands):

	2011	2010	2009
Current:			
Federal	$ 19,810	$ 16,002	$ 1,555
State	551	1,939	(256)
Foreign	19,716	17,628	16,019
	40,077	35,569	17,318
Deferred:			
Federal	39,284	11,367	(71,874)
State	1,658	(653)	(1,831)
Foreign	(1,873)	(2,998)	(1,169)
	39,069	7,716	(74,874)
	$ 79,146	$ 43,285	$ (57,556)

Income tax expense (benefit) 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, 2011, 2010 and 2009 as follows (in thousands):

	2011	2010	2009
Computed expected tax expense (benefit)	$ 77,595	$ 43,786	$ (55,958)
Increase (decrease) resulting from State and foreign income taxes	(3,300)	1,768	(3,712)
Other	4,851	(2,269)	2,114
Income tax	$ 79,146	$ 43,285	$ (57,556)

The tax effects of temporary differences that give rise to significant components of deferred income tax assets and liabilities at December 31, 2011 and 2010 are as follows (in thousands):

	2011	2010
Deferred tax assets:		
Allowance for doubtful accounts	$ 9,054	$ 7,097
Operating loss and tax credit carryforwards	24,101	10,120
Compensation and employee benefits	28,305	29,358
Decommissioning liabilities	39,638	37,909
Deferred interest expense related to exchangeable notes		526
Other	35,005	21,626
Net deferred tax assets	136,103	106,636
Deferred tax liabilities:		
Property, plant and equipment	317,033	248,453
Notes receivable	25,599	23,857
Goodwill and other intangible assets	22,432	19,555
Deferred revenue on long-term contracts	47,341	53,465
Other	21,987	14,595
Deferred tax liabilities	434,392	359,925
Net deferred tax liability	$ 298,289	$ 253,289

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, 2011 and 2010 as follows (in thousands):

	2011	2010
Deferred tax liabilities:		
Current deferred income taxes	$ 831	$ 29,353
Noncurrent deferred income taxes	297,458	223,936
Net deferred tax liability	$ 298,289	$ 253,289

As of December 31, 2011, the Company had approximately $1.8 million in net operating loss carryforwards, which are available to reduce future taxable income. The expiration dates for utilization of the loss carryforwards are 2020 through 2026. Utilization of $0.6 million of the net operating loss carryforwards will be subject to the annual limitations due to the ownership change limitations provided by the Internal Revenue Code of 1986, as amended. As of December 31, 2011, the Company also has various state net operating loss carryforwards of an estimated $60 million with expiration dates from 2020 to 2026. A deferred tax asset of $3.7 million reflects the expected future tax benefit for the state 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, 2011, the undistributed earnings of the Company s foreign subsidiaries were approximately $154 million. If these earnings are repatriated to the United States in the future, additional tax provisions may be required. It is not practicable to estimate the amount of taxes that might be payable on such undistributed earnings.

The 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 2007.

The Company had approximately $21.7 million, $24.8 million and $11.0 million of unrecorded tax benefits at December 31, 2011, 2010 and 2009, respectively, all of which would impact the Company s effective tax rate if recognized.

The activity in unrecognized tax benefits at December 31, 2011, 2010 and 2009 is as follows (in thousands):

	2011	2010	2009
Unrecognized tax benefits,			
December 31, 2010, 2009 and 2008, respectively	$ 24,760	$ 11,013	$ 9,652
Additions based on tax positions related to current year		36	3,377
Additions based on tax positions related to prior years	871	16,607	186
Reductions based on tax positions related to prior years	(3,939)	(2,896)	(2,202)
Unrecognized tax benefits,			
December 31, 2011, 2010 and 2009, respectively	$ 21,692	$ 24,760	$ 11,013

(11) Segment Information

Business Segments

The Company currently has three reportable segments: subsea and well enhancement, drilling products and services, and marine. The subsea and well enhancement segment provides production-related services used to enhance, extend and maintain oil and gas production, which include integrated subsea services and engineering services, mechanical wireline, hydraulic workover and snubbing, well control, coiled tubing, electric line, pumping and stimulation and wellbore evaluation services; well plug and abandonment services; stimulation and sand control equipment and services; and other oilfield services used to support drilling and production operations. The subsea and well enhancement segment also includes production handling arrangements, as well as the production and sale of oil and gas. 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.

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.

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Summarized financial information concerning the Company s segments as of December 31, 2011, 2010 and 2009 and for the years then ended is shown in the following tables (in thousands):

2011	Subsea and Well Enhancement	Drilling Products and Services	Marine	Unallocated	Consolidated Total
Revenues	$ 1,367,834	$ 611,101	$ 91,231	$	$ 2,070,166
Cost of services, rentals, and sales (exclusive of items shown separately below)	832,568	220,647	64,788		1,118,003
Depreciation, depletion, amortization and accretion	115,616	130,801	10,896		257,313
General and administrative	253,550	121,274	8,743		383,567
Reduction in the value of assets			46,096		46,096
Gain on sale of businesses			8,558		8,558
Income (loss) from operations	166,100	138,379	(30,734)		273,745
Interest expense, net				(73,843)	(73,843)
Interest income	4,542			1,684	6,226
Other income	105			(927)	(822)
Earnings from equity-method investments				16,394	16,394
Income (loss) before income taxes	$ 170,747	$ 138,379	$ (30,734)	$ (56,692)	$ 221,700
Identifiable assets	$ 2,863,550	$ 947,679	$ 164,444	$ 72,472	$ 4,048,145
Capital expenditures	$ 286,066	$ 219,121	$ 2,514	$	$ 507,701

2010	Subsea and Well Enhancement	Drilling Products and Services	Marine	Unallocated	Consolidated Total
Revenues	$ 1,112,662	$ 474,707	$ 94,247	$	$ 1,681,616
Cost of services, rentals, and sales (exclusive of items shown separately below)	675,447	176,453	66,813		918,713
Depreciation, depletion, amortization and accretion	95,306	114,722	10,807		220,835
General and administrative	221,615	107,191	14,075		342,881
Reduction in the value of assets			32,004		32,004
Gain on sale of business			1,083		1,083
Income (loss) from operations	120,294	76,341	(28,369)		168,266
Interest expense, net				(57,377)	(57,377)
Interest income	4,548			595	5,143
Other income				825	825
Earnings from equity-method investments				8,245	8,245
Income (loss) before income taxes	$ 124,842	$ 76,341	$ (28,369)	$ (47,712)	$ 125,102
Identifiable assets	$ 1,769,813	$ 802,785	$ 255,883	$ 79,052	$ 2,907,533
Capital expenditures	$ 150,313	$ 142,942	$ 29,989	$	$ 323,244

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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 and amortization	89,986	105,613	11,515		207,114
General and administrative	149,122	90,318	19,653		259,093
Reduction in value of assets	212,527				212,527
Gain on sale of businesses			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 income				571	571
Losses from equity-method investments				(22,600)	(22,600)
Reduction in the value of equity-method investment				(36,486)	(36,486)
Income (loss) before income taxes	$ (148,416)	$ 87,143	$ 9,889	$ (108,495)	$ (159,879)
Identifiable assets	$ 1,377,122	$ 759,418	$ 299,834	$ 80,291	$ 2,516,665
Capital expenditures	$ 99,551	$ 124,845	$ 66,881	$	$ 291,277

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 equipment sold or leased. 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,	
	2011	2010	2009	2011	2010
United States	$ 1,525,296	$ 1,216,295	$ 1,126,071	$ 1,060,483	$ 881,416
Other Countries	544,870	465,321	323,229	446,885	431,734
Total	$ 2,070,166	$ 1,681,616	$ 1,449,300	$ 1,507,368	$ 1,313,150

(12) Guarantee

In connection with the sale of SPN Resources in 2008, the Company guaranteed the performance of its decommissioning liabilities. In accordance with authoritative guidance related to guarantees, the Company has assigned an estimated value of $2.6 million at December 31, 2011 and 2010 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 Dynamic Offshore defaults on the decommissioning liabilities existing at the closing date, the total maximum potential obligation under these guarantees is estimated to be approximately $158.7 million, net of the contractual right to receive payments from third parties, which is approximately $24.6 million, as of December 31, 2011. The total maximum potential obligation will decrease over time as the underlying obligations are fulfilled by SPN Resources.

(13) 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 $18.3 million, $15.1 million and $12.0 million in 2011, 2010 and 2009, respectively. Future minimum lease payments under non-cancelable leases for the five years ending December 31, 2012 through 2016 and thereafter are as follows: $20.7 million, $17.0 million, $14.3 million, $10.8 million, $9.1 million and $30.7 million, 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.

(14) Fair Value Measurements

The Company follows authoritative guidance for fair value measurements relating to financial and nonfinancial assets and liabilities, including presentation of required disclosures herein. This guidance 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.

The following table provides a summary of the financial assets and liabilities measured at fair value on a recurring basis at December 31, 2011 and December 31, 2010 (in thousands):

	December 31, 2011	Fair Value Measurements at Reporting Date Using		
		Level 1	Level 2	Level 3
Intangible and other long-term assets				
Non-qualified deferred compensation assets	$ 10,597	$ 815	$ 9,782	
Interest rate swap	$ 1,904		$ 1,904	
Accounts payable				
Non-qualified deferred compensation liabilities	$ 2,790		$ 2,790	
Other long-term liabilities				
Non-qualified deferred compensation liabilities	$ 12,975		$ 12,975	

	December 31, 2010	Level 1	Level 2	Level 3
Intangible and other long-term assets				
Non-qualified deferred compensation assets	$ 10,820	$ 812	$ 10,008	
Interest rate swap	$ 161		$ 161	
Accounts payable				
Non-qualified deferred compensation liabilities	$ 2,953	$ 1,429	$ 1,524	
Other long-term liabilities				
Non-qualified deferred compensation liabilities	$ 14,236		$ 14,236	

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 9). 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 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 represent Levels 1 and 2, respectively in the fair value hierarchy.

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In March 2010, the Company entered into an interest rate swap agreement for a notional amount of $150 million, whereby the Company is entitled to receive semi-annual interest payments at a fixed rate of 6 $^{7}/8$% per annum and is obligated to make quarterly interest payments at a floating rate, which is adjusted every 90 days, based on LIBOR plus a fixed margin.

In accordance with authoritative guidance, non-financial assets and non-financial liabilities are remeasured at fair value on a non-recurring basis. During the year ended 2011, the Company wrote off approximately $46.1 million of certain long-lived assets to approximate the indicated fair value of the liftboats from prospective purchasers. During the year ended December 31, 2010, the Company wrote off approximately $32.0 million of long-lived liftboat components primarily related to the two partially completed liftboats. During the year ended December 31, 2009, the Company identified impairments of certain long-lived assets of approximately $212.5 million. Additionally, during 2009, the Company recorded a $36.5 million reduction in the value of its equity-method investment in BOG.

The following table reflects the fair value measurements used in testing the impairment of long-lived assets during the years ended December 31, 2011, 2010 and 2009 (in thousands):

		Fair Value Measurements at Reporting Date Using			
	December 31, 2011	(Level 1)	(Level 2)	(Level 3)	Total Losses
Property, plant and equipment, net	$ 134,000			$ 134,000	$ (35,762)
Goodwill	$ - 0 -			$ - 0 -	$ (10,334)
	December 31, 2010	(Level 1)	(Level 2)	(Level 3)	Total Losses
Property, plant and equipment, net	$ - 0 -			$ - 0 -	$ (32,004)
	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)

(15) Derivative Financial Instruments

From time to time, the Company may employ interest rate swaps in an attempt to achieve a more balanced debt portfolio. The Company does not use derivative financial instruments for trading or speculative purposes.

In March 2010, the Company entered into an interest rate swap agreement for a notional amount of $150 million related to its fixed rate debt maturing on June 1, 2014. This transaction was designated as a fair value hedge since the swap hedges against the change in fair value of fixed rate debt resulting from changes in interest rates. The Company recorded a derivative asset of $1.9 million and $0.2 million, respectively, within intangible and other long-term assets in the consolidated balance sheet at December 31, 2011 and 2010. The change in fair value of the interest rate swap is included in the adjustments to reconcile net income to net cash provided by operating activities in the consolidated statements of cash flows.

The location and effect of the derivative instrument on the consolidated statements of operations for the years ended December 31, 2011 and 2010, presented on a pre-tax basis, is as follows (in thousands):

	Location of (gain) loss recognized	Amount of (gain) loss recognized in the year ending December 31, 2011	2010
Interest rate swap	Interest expense, net	$ 793	$ (1,742)
Hedged item debt	Interest expense, net	(2,536)	1,581

	$ (1,743)	$ (161)

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For the years ended December 31, 2011 and 2010, approximately $1.7 million and $0.2 million, respectively, of interest income was related to the ineffectiveness associated with this fair value hedge. Hedge ineffectiveness represents the difference between the changes in fair value of the derivative instruments and the changes in fair value of the fixed rate debt attributable to changes in the benchmark interest rate.

This interest rate swap exposes the Company to credit risk to the extent that the counterparty may be unable to meet the terms of agreement. The counterparty to this agreement is a major financial institution which has an investment grade credit rating and is considered well-capitalized under applicable regulatory capital adequacy guidelines. Should the counterparty to this interest rate swap agreement fail to perform according to the terms of the contract, the Company would be required to pay interest at the stated rate of 6 7/8% related to its $300 million of unsecured senior notes with a maturity date of 2014.

(16) Financial Information of Guarantor Subsidiaries

In April 2011, SESI, L.L.C. (Issuer), a wholly-owned subsidiary of Superior Energy Services, Inc. (Parent), issued $500 million of unsecured 6 $^{3}/8$% senior notes due 2019. In December 2011, SESI, L.L.C. issued $800 million of unsecured 7 $^{1}/8$% senior notes due 2021. The Parent, along with substantially all of its domestic subsidiaries, fully and unconditionally guaranteed the senior notes, and such guarantees are joint and several. All of the guarantor subsidiaries are wholly-owned subsidiaries of the Issuer. Domestic income taxes are paid by the Parent through a consolidated tax return and are accounted for by the Parent. In 2011, the Company reorganized its international legal entities. The following tables present the condensed consolidating balance sheets as of December 31, 2011 and 2010, and the condensed consolidating statements of operations and cash flows for the years ended December 31, 2011, 2010 and 2009.

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidating Balance Sheets

December 31, 2011

(in thousands)

	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$	$ 29,057	$ 6,272	$ 44,945	$	$ 80,274
Accounts receivable, net		531	437,963	143,444	(41,336)	540,602
Income taxes receivable				698	(698)	
Prepaid expenses	34	3,893	9,796	20,314		34,037
Inventory and other current assets		1,796	214,381	12,132		228,309
Total current assets	34	35,277	668,412	221,533	(42,034)	883,222
Property, plant and equipment, net		2,758	1,096,036	408,574		1,507,368
Goodwill			437,614	143,765		581,379
Notes receivable			73,568			73,568
Investments in subsidiaries	124,271	1,152,918			(1,277,189)	
Equity-method investments		70,614		1,858		72,472
Intangible and other long-term assets, net		828,447	71,625	30,064		930,136
Total assets	$ 124,305	$ 2,090,014	$ 2,347,255	$ 805,794	$ (1,319,223)	$ 4,048,145
LIABILITIES AND STOCKHOLDERS EQUITY						
Current liabilities:						
Accounts payable	$	$ 4,307	$ 128,996	$ 86,723	$ (41,381)	$ 178,645
Accrued expenses	164	54,000	105,512	38,503	(605)	197,574
Income taxes payable	1,415				(698)	717
Deferred income taxes	831					831
Current portion of decommissioning liabilities			14,956			14,956
Current maturities of long-term debt				810		810
Total current liabilities	2,410	58,307	249,464	126,036	(42,684)	393,533
Deferred income taxes	285,871			11,587		297,458
Decommissioning liabilities			108,220			108,220
Long-term debt, net		1,673,351		11,736		1,685,087
Intercompany payables/(receivables)	(96,987)	988,160	(253,050)	(7,276)	(630,847)	
Other long-term liabilities	5,192	32,380	26,704	45,972		110,248
Stockholders equity:						
Preferred stock of $.01 par value						
Common stock of $.001 par value	80			4,212	(4,212)	80
Additional paid in capital	447,007	124,271		517,209	(641,480)	447,007
Accumulated other comprehensive loss, net				(26,936)		(26,936)
Retained earnings (accumulated deficit)	(519,268)	(786,455)	2,215,917	123,254		1,033,448

Total stockholders equity (deficit)	(72,181)	(662,184)	2,215,917	617,739	(645,692)	1,453,599
Total liabilities and stockholders equity	$ 124,305	$ 2,090,014	$ 2,347,255	$ 805,794	$ (1,319,223)	$ 4,048,145

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidating Balance Sheets

December 31, 2010

(in thousands)

	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS						
Current assets:						
Cash and cash equivalents	$	$	$ 5,493	$ 45,234	$	$ 50,727
Accounts receivable, net		415	382,935	99,010	(29,910)	452,450
Income taxes receivable				2,024	(2,024)	
Prepaid expenses	18	4,128	8,948	12,734		25,828
Inventory and other current assets		1,678	222,822	10,547		235,047
Intercompany interest receivable		15,883			(15,883)	
Total current assets	18	22,104	620,198	169,549	(47,817)	764,052
Property, plant and equipment, net		3,189	957,561	352,400		1,313,150
Goodwill			447,467	140,533		588,000
Notes receivable			69,026			69,026
Intercompany notes receivable		456,280			(456,280)	
Investments in subsidiaries	124,271	602,461	4,347	4,347	(735,426)	
Equity-method investments		43,947		15,375		59,322
Intangible and other long-term assets, net		22,455	61,722	29,806		113,983
Total assets	$ 124,289	$ 1,150,436	$ 2,160,321	$ 712,010	$ (1,239,523)	$ 2,907,533
LIABILITIES AND STOCKHOLDERS EQUITY						
Current liabilities:						
Accounts payable	$	$ 6,654	$ 71,790	$ 64,636	$ (32,804)	$ 110,276
Accrued expenses	153	42,821	91,451	27,619		162,044
Income taxes payable	4,499				(2,024)	2,475
Deferred income taxes	29,353					29,353
Current portion of decommissioning liabilities			16,929			16,929
Current maturities of long-term debt		184,000		810		184,810
Intercompany interest payable				15,883	(15,883)	
Total current liabilities	34,005	233,475	180,170	108,948	(50,711)	505,887
Deferred income taxes	211,173			12,763		223,936
Decommissioning liabilities			100,787			100,787
Long-term debt, net		669,089		12,546		681,635
Intercompany notes payable				456,280	(456,280)	
Intercompany payables/(receivables)	(100,882)	760,164	(1,407)	(125,246)	(532,629)	
Other long-term liabilities	8,260	37,537	19,427	49,513		114,737
Stockholders equity:						
Preferred stock of $.01 par value			4,347	4,347	(8,694)	
Common stock of $.001 par value	79			176	(176)	79

Additional paid in capital	415,278	124,271		66,762	(191,033)	415,278
Accumulated other comprehensive loss, net				(25,700)		(25,700)
Retained earnings (accumulated deficit)	(443,624)	(674,100)	1,856,997	151,621		890,894
Total stockholders equity (deficit)	(28,267)	(549,829)	1,861,344	197,206	(199,903)	1,280,551
Total liabilities and stockholders equity	$ 124,289	$ 1,150,436	$ 2,160,321	$ 712,010	$ (1,239,523)	$ 2,907,533

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidating Statements of Operations

Year Ended December 31, 2011

(in thousands)

	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$	$	$ 1,730,780	$ 408,497	$ (69,111)	$ 2,070,166
Cost of services (exclusive of items shown separately below)			890,800	295,998	(68,795)	1,118,003
Depreciation, depletion, amortization and accretion		523	211,988	44,802		257,313
General and administrative expenses	683	81,363	236,229	65,608	(316)	383,567
Reduction in value of assets			46,096			46,096
Gain on sale of businesses			8,558			8,558
Income (loss) from operations	(683)	(81,886)	354,225	2,089		273,745
Other income (expense):						
Interest expense, net		(72,414)	(24)	(1,405)		(73,843)
Interest income		1,097	4,536	593		6,226
Intercompany interest income (expense)		26,673		(26,673)		
Other income (expense)		(1,005)	183			(822)
Earnings (losses) from equity-method investments, net		15,180		1,214		16,394
Income (loss) before income taxes	(683)	(112,355)	358,920	(24,182)		221,700
Income taxes	74,961			4,185		79,146
Net income (loss)	$ (75,644)	$ (112,355)	$ 358,920	$ (28,367)	$	$ 142,554

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidating Statements of Operations

Year Ended December 31, 2010

(in thousands)

	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$	$	$ 1,414,519	$ 339,233	$ (72,136)	$ 1,681,616
Cost of services (exclusive of items shown separately below)			759,447	231,082	(71,816)	918,713
Depreciation, depletion, amortization and accretion		515	181,216	39,104		220,835
General and administrative expenses	322	99,068	190,665	53,146	(320)	342,881
Reduction in value of assets			32,004			32,004
Gain on sale of business			1,083			1,083
Income (loss) from operations	(322)	(99,583)	252,270	15,901		168,266
Other income (expense):						
Interest expense, net		(53,716)	(216)	(3,445)		(57,377)
Interest income		150	4,467	526		5,143
Intercompany interest income (expense)		15,883		(15,883)		
Other income (expense)		825				825
Earnings (losses) from equity-method investments, net		985		7,260		8,245
Income (loss) before income taxes	(322)	(135,456)	256,521	4,359		125,102
Income taxes	37,662			5,623		43,285
Net income (loss)	$ (37,984)	$ (135,456)	$ 256,521	$ (1,264)	$	$ 81,817

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Consolidating Statements of Operations

Year Ended December 31, 2009

(in thousands)

	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues	$	$	$ 1,307,542	$ 186,807	$ (45,049)	$ 1,449,300
Cost of services (exclusive of items shown separately below)			763,029	106,054	(45,049)	824,034
Depreciation and accretion		476	184,084	22,554		207,114
General and administrative expenses	(184)	61,035	168,459	29,783		259,093
Reduction in value of assets			212,527			212,527
Gain on sale of businesses			2,084			2,084
Income (loss) from operations	184	(61,511)	(18,473)	28,416		(51,384)
Other income (expense):						
Interest expense, net		(48,894)	(68)	(1,944)		(50,906)
Interest income		87	670	169		926
Intercompany interest income (expense)						
Other income (expense)		571				571
Earnings (losses) from equity-method investments, net		(21,631)		(969)		(22,600)
Reduction in value of equity-method investments		(36,486)				(36,486)
Income (loss) before income taxes	184	(167,864)	(17,871)	25,672		(159,879)
Income taxes	(65,805)			8,249		(57,556)
Net income (loss)	$ 65,989	$ (167,864)	$ (17,871)	$ 17,423	$	$ (102,323)

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2011

(in thousands)

	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ (75,644)	$ (112,355)	$ 358,920	$ (28,367)	$ 142,554
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation, depletion, amortization and accretion		523	211,988	44,802	257,313
Deferred income taxes	49,946			(1,873)	48,073
Excess tax benefit from stock-based compensation	(9,004)				(9,004)
Reduction in value of assets			46,096		46,096
Stock-based and performance share unit compensation expense		14,032			14,032
Retirement and deferred compensation plans expense		1,990			1,990
(Earnings) losses from equity-method investments, net of cash received		(12,001)		(1,151)	(13,152)
Amortization of debt acquisition costs and note discount		25,154		24	25,178
Gain on sale of businesses			(8,558)		(8,558)
Other reconciling items, net		(1,884)	(4,542)		(6,426)
Changes in operating assets and liabilities, net of acquisitions and dispositions:					
Accounts receivable		(117)	(51,133)	(35,564)	(86,814)
Inventory and other current assets		(117)	5,348	(3,049)	2,182
Accounts payable		(2,348)	26,499	16,138	40,289
Accrued expenses	12	7,983	11,801	5,165	24,961
Decommissioning liabilities			(504)		(504)
Income taxes	(917)			(461)	(1,378)
Other, net	(16)	(1,024)	18,646	(1,634)	15,972
Net cash provided by operating activities	(35,623)	(80,164)	614,561	(5,970)	492,804
Cash flows from investing activities:					
Payments for capital expenditures		(93)	(383,785)	(100,770)	(484,648)
Change in restricted cash held for acquisition of a business		(785,280)			(785,280)
Purchase of short-term investments		(223,491)			(223,491)
Proceeds from sale of short-term investments		223,630			223,630
Acquisitions of businesses, net of cash acquired			(1,200)	(548)	(1,748)
Proceeds from sale of businesses			22,349		22,349
Other			(721)		(721)
Intercompany receivables/payables	14,485	125,015	(250,425)	110,925	
Net cash used in investing activities	14,485	(660,219)	(613,782)	9,607	(1,249,909)
Cash flows from financing activities:					
Net (payments) borrowings from revolving line of credit		(100,000)			(100,000)
Proceeds from issuance of long-term debt		1,300,000			1,300,000
Principal payments on long-term debt		(400,000)		(810)	(400,810)
Payment of debt issuance costs		(24,428)			(24,428)
Proceeds from exercise of stock options	10,263				10,263
Excess tax benefit from stock-based compensation	9,004				9,004
Proceeds from issuance of stock through employee benefit plans	2,206				2,206
Other	(335)	(6,132)		(3,195)	(9,662)
Net cash used in financing activities	21,138	769,440		(4,005)	786,573
Effect of exchange rate changes on cash				79	79

Net increase (decrease) in cash and cash equivalents		29,057	779	(289)	29,547
Cash and cash equivalents at beginning of period			5,493	45,234	50,727
Cash and cash equivalents at end of period	$	$ 29,057	$ 6,272	$ 44,945	$ 80,274

SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2010

(in thousands)

	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ (37,984)	$ (135,456)	$ 256,521	$ (1,264)	$ 81,817
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation, depletion, amortization and accretion		515	181,216	39,104	220,835
Deferred income taxes	10,650			(2,374)	8,276
Excess tax benefit from stock-based compensation	(560)				(560)
Reduction in value of assets			32,004		32,004
Stock-based and performance share unit compensation expense		27,207			27,207
Retirement and deferred compensation plans expense		4,825			4,825
(Earnings) losses from equity-method investments, net of cash received		9,005		(6,100)	2,905
Amortization of debt acquisition costs and note discount		23,954			23,954
Gain on sale of business			(1,083)		(1,083)
Other reconciling items, net		(161)	(4,547)		(4,708)
Changes in operating assets and liabilities, net of acquisitions and dispositions:					
Accounts receivable		275	(76,669)	(13,406)	(89,800)
Inventory and other current assets		163	89,302	(3,778)	85,687
Accounts payable		2,001	18,928	(626)	20,303
Accrued expenses	38	5,800	1,735	7,181	14,754
Decommissioning liabilities			(1,759)		(1,759)
Income taxes	13,536			(3,026)	10,510
Other, net	(1,417)	(3,143)	21,280	4,086	20,806
Net cash provided by operating activities	(15,737)	(65,015)	516,928	19,797	455,973
Cash flows from investing activities:					
Payments for capital expenditures			(218,726)	(104,518)	(323,244)
Acquisitions of businesses, net of cash acquired			(56,560)	(219,517)	(276,077)
Proceeds from sale of business			5,250		5,250
Other		2,387	(11,537)	(252)	(9,402)
Intercompany receivables/payables	12,359	(102,093)	(234,733)	324,467	
Net cash used in investing activities	12,359	(99,706)	(516,306)	180	(603,473)
Cash flows from financing activities:					
Net (payments) borrowings from revolving line of credit		(2,000)			(2,000)
Principal payments on long-term debt				(810)	(810)
Payment of debt issuance costs		(5,182)			(5,182)
Proceeds from exercise of stock options	927				927
Excess tax benefit from stock-based compensation	560				560
Proceeds from issuance of stock through employee benefit plans	1,891				1,891
Other				(3,443)	(3,443)
Net cash used in financing activities	3,378	(7,182)		(4,253)	(8,057)

Effect of exchange rate changes on cash				(221)	(221)
Net increase (decrease) in cash and cash equivalents		(171,903)	622	15,503	(155,778)
Cash and cash equivalents at beginning of period		171,903	4,871	29,731	206,505
Cash and cash equivalents at end of period	$	$	$ 5,493	$ 45,234	$ 50,727

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SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Condensed Consolidating Statements of Cash Flows

Year Ended December 31, 2009

(in thousands)

	Parent	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash flows from operating activities:					
Net income (loss)	$ 65,989	$ (167,864)	$ (17,871)	$ 17,423	$ (102,323)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation and amortization		476	184,084	22,554	207,114
Deferred income taxes	(73,127)			(1,577)	(74,704)
Excess tax benefit from stock-based compensation	(170)				(170)
Reduction in value of assets			212,527		212,527
Reduction in value of equity-method investments		36,486			36,486
Stock-based and performance share unit compensation expense		11,785			11,785
Retirement and deferred compensation plans expense		1,550			1,550
(Earnings) losses from equity-method investments, net of cash received		27,637		969	28,606
Amortization of debt acquisition costs and note discount		21,744			21,744
Gain on sale of businesses			(2,084)		(2,084)
Changes in operating assets and liabilities, net of acquisitions and dispositions:					
Accounts receivable		(156)	19,940	5,825	25,609
Inventory and other current assets		(211)	(48,786)	(2,323)	(51,320)
Accounts payable		609	(27,786)	2,540	(24,637)
Accrued expenses	(469)	(13,381)	(27,381)	(33)	(41,264)
Income taxes	4,270			(6,571)	(2,301)
Other, net	1,970	6,925	17,493	3,097	29,485
Net cash provided by operating activities	(1,537)	(74,400)	310,136	41,904	276,103
Cash flows from investing activities:					
Payments for capital expenditures			(240,907)	(45,370)	(286,277)
Acquisitions of businesses, net of cash acquired			(1,247)		(1,247)
Proceeds from sale of businesses			7,716		7,716
Cash contributed to equity-method investment				(8,694)	(8,694)
Other		(3,769)			(3,769)
Intercompany receivables/payables	(966)	64,509	(76,684)	13,141	
Net cash used in investing activities	(966)	60,740	(311,122)	(40,923)	(292,271)
Cash flows from financing activities:					
Net (payments) borrowings from revolving line of credit		177,000			177,000
Principal payments on long-term debt				(810)	(810)
Payment of debt issuance costs		(2,308)			(2,308)
Proceeds from exercise of stock options	375				375
Excess tax benefit from stock-based compensation	170				170
Proceeds from issuance of stock through employee benefit plans	1,958				1,958
Net cash used in financing activities	2,503	174,692		(810)	176,385
Effect of exchange rate changes on cash				1,435	1,435

Net increase (decrease) in cash and cash equivalents		161,032	(986)	1,606	161,652
Cash and cash equivalents at beginning of period		10,871	5,857	28,125	44,853
Cash and cash equivalents at end of period	$	$ 171,903	$ 4,871	$ 29,731	$ 206,505

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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, 2011 and 2010 (amounts in thousands, except per share data).

	Three Months Ended			
	March 31	June 30	Sept. 30	Dec. 31
2011				
Revenues	$ 413,981	$ 510,806	$ 565,342	$ 580,037
Less:				
Cost of services, rentals and sales	233,845	271,370	301,065	311,723
Depreciation, depletion, amortization and accretion	59,363	63,314	64,875	69,761
Gross profit	120,773	176,122	199,402	198,553
Net income	15,503	48,109	59,580	19,362
Earnings per share:				
Continuing operations				
Basic	$ 0.20	$ 0.60	$ 0.75	$ 0.24
Diluted	0.19	0.59	0.73	0.25

	Three Months Ended			
	March 31	June 30	Sept. 30	Dec. 31
2010				
Revenues	$ 364,511	$ 424,856	$ 435,353	$ 456,896
Less:				
Cost of services, rentals and sales	199,052	229,916	232,308	257,437
Depreciation, depletion, amortization and accretion	51,048	54,299	56,805	58,683
Gross profit	114,411	140,641	146,240	140,776
Net income	21,526	24,065	33,217	3,009
Earnings (loss) per share:				
Continuing operations				
Basic	$ 0.27	$ 0.31	$ 0.42	$ 0.04
Diluted	0.27	0.30	0.42	0.04

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

On January 31, 2010, Wild Well acquired 100% ownership of Shell Offshore, Inc. s Gulf of Mexico Bullwinkle platform and its related assets and assumed the related decommissioning obligation. Immediately after Wild Well acquired these assets, it conveyed an undivided 49% interest in these assets and the related well plugging and abandonment obligations to Dynamic Offshore, which operates these assets (see note 3). The Company also has an interest in oil and gas operations through its equity-method investment in Dynamic Offshore (see note 7).

In January 2010, the Financial Accounting Standards Board issued an update to the authoritative guidance related to oil and gas reserve estimation and disclosures 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.

The Company s December 31, 2011 estimates of proved reserves are based on reserve reports prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The Company s December 31, 2010 estimates of proved reserves were based on reserve reports prepared by DeGoyler and MacNaughton and Netherland, Sewell & Associates, Inc. Users of this information should be aware that the process of estimating quantities of proved , proved developed and proved undeveloped natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of

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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. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion.

Oil and Natural Gas Reserves

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

	Consolidated		Company s Share of Equity-Method Investments	
	Crude Oil (Mbbls)	Natural Gas (Mmcf)	Crude Oil (Mbbls)	Natural Gas (Mmcf)
Proved-developed and undeveloped reserves:				
December 31, 2009			3,242	23,255
Purchase of reserves in place	5,686	4,377	34	8
Revisions	723	1,572	564	692
Extensions, discoveries and other additions				413
Change in ownership percentage			(32)	(1,347)
Production	(427)	(648)	(413)	(2,910)
December 31, 2010	5,982	5,301	3,395	20,111
Purchase of reserves in place			958	8,045
Revisions	887	1,338	412	(547)
Extensions, discoveries and other additions				
Sale of reserves in-place			(1,159)	(8,467)
Production	(439)	(371)	(399)	(906)
December 31, 2011	6,430	6,268	3,207	18,236
Proved-developed reserves:				
December 31, 2010	4,166	3,848	2,972	18,228
December 31, 2011	3,495	3,229	2,606	14,695
Proved-undeveloped reserves:				
December 31, 2010	1,817	1,453	423	1,885
December 31, 2011	2,935	3,039	602	3,542

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Costs Incurred in Oil and Natural Gas Activities

The following table displays certain information regarding the costs incurred associated with finding, acquiring and developing the Company s proved oil and natural gas reserves for the years ended December 31, 2011 and 2010 (in thousands).

	Consolidated Years Ended December 31,		Company s Share of Equity-Method Investments Years Ended December 31,	
	2011	2010	2011	2010
Acquisition of properties proved	$	$ 34,336	$ 32,586	$ 629
Acquisition of properties unproved				118
Exploratory costs		359		
Development costs	10,560	30	18,367	9,980
Total costs incurred	$ 10,560	$ 34,725	$ 50,953	$ 10,727

Capitalized costs for oil and gas producing activities consist of the following (in thousands):

	Consolidated Years Ended December 31,		Company s Share of Equity-Method Investments Years Ended December 31,	
	2011	2010	2011	2010
Unproved oil and gas properties	$	$	$ 13,559	$ 24,097
Proved oil and gas properties	44,109	34,336	159,527	144,324
Accumulated depreciation, depletion and amortization	(8,215)	(3,038)	(52,764)	(49,849)
Capitalized costs, net	$ 35,894	$ 31,298	$ 120,322	$ 118,572

Productive Wells Summary

The following table presents the Company s ownership of productive oil and natural gas wells as of December 31, 2011. Productive wells consist of producing wells and wells capable of production. In the table, gross refers to the total wells in which the Company owns an interest and net refers to the sum of fractional interests owned in gross wells.

	Consolidated Total Productive Wells		Company s Share of Equity-Method Investments Total Productive Wells	
	Gross	Net	Gross	Net
Oil	10.00	5.10	28.50	18.13
Natural gas			22.70	11.07
Total	10.00	5.10	51.20	29.20

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Acreage

The following table sets forth information as of December 31, 2011 relating to acreage held by the Company. Developed acreage is assigned to productive wells.

	Consolidated		Company s Share of Equity-Method Investments	
	Gross Acreage	Net Acreage	Gross Acreage	Net Acreage
Developed	17,280	8,813	69,517	38,434
Undeveloped			5,560	4,574
Total	17,280	8,813	75,077	43,008

Drilling Activity

The following table shows the Company s drilling activity for the years ended December 31, 2011 and 2010. The Company did not engage in any drilling activity related to its ownership of the Bullwinkle platform and its related assets during the year ended December 31, 2011. In the table, gross refers to the total wells in which the Company has a working interest and net refers to the gross wells multiplied by the Company s working interest in these wells. Well activity refers to the number of wells completed during a fiscal year, regardless of when drilling first commenced.

	Company s Share of Equity-Method Investments			
	2011		2010	
	Gross	Net	Gross	Net
Exploratory Wells				
Productive	0.10	0.01		
Non-productive	0.10	0.07		
Total	0.20	0.08		
Development Wells				
Productive	0.20	0.03	0.25	0.15
Non-productive	0.10	0.02		
Total	0.30	0.05	0.25	0.15

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Results of Operations

The following table sets forth the Company s results of operations for producing activities:

	Years Ended December 31, 2011	2010
Consolidated Entities		
Revenues		
Sales	$ 54,442	$ 39,410
Production costs	12,293	9,511
Exploration expenses		359
Depreciation, depletion and amortization	11,928	10,057
	30,221	19,483
Income tax expenses	10,789	7,014
Results of operations from producing activities (excluding corporate overhead)	$ 19,432	$ 12,469
Company s share of equity-method investments		
Revenues		
Sales	$ 53,181	$ 56,964
Production costs	22,034	23,375
Exploration expenses		105
Depreciation, depletion and amortization	18,449	18,557
	12,698	14,927
Income tax expenses	4,533	5,373
Results of operations from producing activities (excluding corporate overhead)	$ 8,165	$ 9,554

The Company s consolidated oil and gas operations, as well as its share of equity-method investment are in the Gulf of Mexico. The Company s consolidated entity s average sales price was $108.79 per barrel of oil and $3.45 per mcf of gas in 2011 and $77.04 per barrel of oil and $5.00 per mcf of gas in 2010. Average production costs were $12.51 and $19.99 per barrel of oil equivalent in years ended December 31, 2011 and 2010, respectively. The Company s share of its equity-method investment s average sales price was $113.28 per barrel of oil and $4.40 per mcf of gas in 2011 and $79.21 per barrel of oil and $4.78 per mcf of gas in 2010. Average production costs were $26.30 and $25.35 per barrel of oil equivalent in 2011 and 2010, respectively.

Standardized Measure of Discounted Future Net Cash Flows Relating to Reserves

The following information has been developed utilizing procedures prescribed by authoritative guidance related to oil and gas activities. It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account in reviewing this information: (1) future costs and selling prices will likely 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.

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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. 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 authoritative guidance related to oil and gas activities.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves at December 31, 2011 and 2010 is as follows (in thousands):

	Consolidated		Company s Share of Equity-Method Investments	
	2011	2010	2011	2010
Future cash inflows	$ 701,170	$ 486,199	$ 414,246	$ 356,126
Future production costs	(126,627)	(43,392)	(100,848)	(83,215)
Future development and abandonment costs	(58,388)	(86,125)	(67,760)	(84,260)
Future income tax expenses	(185,816)	(129,262)	(73,202)	(66,161)
Future net cash flows	330,339	227,420	172,436	122,490
10% annual discount for estimated timing of cash flows	92,590	57,928	39,704	20,014
Standardized measure of discounted future net cash flows	$ 237,749	$ 169,492	$ 132,732	$ 102,476

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, 2011 and 2010 is as follows (in thousands):

	Consolidated		Company s Share of Equity-Method Investment	
	2011	2010	2011	2010
Beginning of the period	$ 169,492	$	$ 102,476	$ 64,136
Net change in sales and transfer prices and in production (lifting) costs related to future production	62,881	102,726	27,944	57,626
Changes in estimated future development costs	8,297	2,950	(8,862)	(9,051)
Sales and transfers of oil and gas produced during the period	(54,057)	(29,542)	(44,268)	(32,370)
Net change due to extensions, discoveries, and improved recovery				2,781
Net changes due to purchases and sales of minerals in place		70,993	51,781	(1,912)
Net changes due to revisions in quantity estimates	57,189	38,206	22,005	16,859
Previously estimated development costs incurred during the period	17,980	1,758	13,840	16,570
Exchange transaction			(23,356)	
Accretion of discount	26,625	16,484	11,179	8,780
Other-unspecified	(12,650)	2,338	(2,065)	1,496
Net change in income taxes	(38,008)	(36,421)	(17,942)	(22,439)
Aggregate change in the standardized measure of discounted future net cash flows for the year	68,257	169,492	30,256	38,340
End of the period	$ 237,749	$ 169,492	$ 132,732	$ 102,476

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The December 31, 2011 amount was estimated by Netherland, Sewell & Associates, Inc. using a twelve month average WTI Cushing price of $96.19 per barrel (bbl), and a Henry Hub gas price of $4.118 per million British Thermal Units, and price differentials. The December 31, 2010 amount was estimated by DeGoyler and MacNaughton and Netherland, Sewell & Associates, Inc. using a twelve month average WTI Cushing price of $79.40 per barrel (bbl), and a Henry Hub gas price of $4.38 per million British Thermal Units, and price differentials.

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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, 2011 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 Annual 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, 2011, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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Management s Annual 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, 2011. 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, 2011 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, 2011, our internal control over financial reporting was effective based on those criteria.

Our internal control over financial reporting as of December 31, 2011 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, 2011, 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 Annual 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, 2011, 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, 2011 and 2010, 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, 2011, and our report dated February 28, 2012 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

New Orleans, Louisiana

February 28, 2012

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Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information relating to our executive officers is included in Part I, Item 1 in this Annual Report, and is incorporated herein by reference. Information relating to our Code of Business Ethics and Conduct that applies to all of our directors, officers and employees, including our senior financial officers, is included in Part I, Item 1 of this Annual Report, 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:

(2) Financial Statement Schedule

All other schedules are omitted because they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

(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 to Superior Energy Services, Inc. s Form 8-K filed December 11, 2009 (File No. 001-34037)).
2.2	Rule 2.5 Announcement (incorporated herein by reference to Exhibit 2.2 to Superior Energy Services, Inc. s Form 8-K filed December 11, 2009 (File No. 001-34037)).
2.3	Agreement and Plan of Merger, dated October 9, 2011, by and among Superior Energy Services, Inc., SPN Fairway Acquisition, Inc. and Complete Production Services, Inc. (incorporated herein by reference to Exhibit 2.1 to Superior Energy Services, Inc. s Form 8-K filed October 12, 2011 (File No. 001-34037)).
3.1*	Composite Certificate of Incorporation of Superior Energy Services, Inc.
3.2	Amended and Restated Bylaws of Superior Energy Services, Inc. (as amended through February 23, 2011) (incorporated herein by reference to Exhibit 3.1 to Superior Energy Services, Inc. s Form 8-K filed February 25, 2011 (File No. 001-34037)).
4.1	Specimen Stock Certificate (incorporated herein by reference to Amendment No. 1 to Superior Energy Services, Inc. s Form S-4 on Form SB-2 (Registration Statement No. 33-94454)).

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Exhibit No.	Description
4.2	Indenture, dated May 22, 2006, among 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 Superior Energy Services, Inc. s Form 8-K filed May 23, 2006 (File No. 333-22603)), 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 Superior Energy Services, Inc. s 8-K filed December 13, 2006 (File No. 333-22603)), as further amended by Supplemental Indenture, dated September 13, 2007 but effective as of August 29, 2007, by and among Advanced Oilwell Services, Inc., 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 Superior Energy Services, Inc. s Form 8-K filed September 18, 2007 (File No. 333-22603)), as further amended by Supplemental Indenture, dated April 27, 2011, among Superior Energy Services Colombia, L.L.C., SESI, L.L.C., Superior Energy Services, Inc., the other Guarantors (as defined in the Indenture referred to therein) and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.3 to Superior Energy Services, Inc. s Form 8-K filed April 27, 2011 (File No. 001-34037)).
4.3	Indenture, dated April 27, 2011, among SESI, L.L.C., each of the guarantors party thereto and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to Superior Energy Services, Inc. s Form 8-K filed April 27, 2011 (File No. 001-34037)).
4.4	Indenture, dated December 6, 2011, among SESI, L.L.C., each of the guarantors party thereto and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to Superior Energy Services, Inc. s Form 8-K filed December 12, 2011 (File No. 001-34037)).
10.1^	Amended and Restated Superior Energy Services, Inc. 1995 Stock Incentive Plan (incorporated herein by reference to Exhibit A to Superior Energy Services, Inc. s Definitive Proxy Statement filed June 26, 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 (Superior Energy Services, Inc. agrees to furnish supplementally a copy of any omitted exhibits to the SEC upon request) (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed January 4, 2008 (File No. 333-22603)).
10.3^	Form of Employment Agreement for Robert S. Taylor (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed June 6, 2007 (File No. 333-22603)).

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Exhibit No.	Description
10.4^	Superior Energy Services, Inc. 2007 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed May 24, 2007 (File No. 333-22603)).
10.5^	Form of Employment Agreement executed by Superior Energy Services, Inc. and each of Alan P. Bernard, Lynton G. Cook, III and Danny R. Young (incorporated herein by reference to Exhibit 10.2 to Superior Energy Services, Inc. s Form 8-K filed June 6, 2007 (File No. 333-22603)).
10.6^	Superior Energy Services, Inc. 1999 Stock Incentive Plan (incorporated herein by reference to Superior Energy Services, Inc. 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 Superior Energy Services, Inc. s Form 8-K filed December 20, 2004 (File No. 333-22603)).
10.7^	Amended and Restated Superior Energy Services, Inc. 2002 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.9 to Superior Energy Services, Inc. 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 Superior Energy Services, Inc. s Form 8-K filed December 20, 2004 (File No. 333-22603)).
10.8^	Superior Energy Services, Inc. Nonqualified Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.11 to Superior Energy Services, Inc. s Annual Report on Form 10-K for the year ended December 31, 2009), as amended by Amendment No. 1 to the Superior Energy Nonqualified Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.11 of Superior Energy Services, Inc. s Form 10-K for the year ended December 31, 2011 (File No. 001-34037)).
10.9^	Superior Energy Services, Inc. 2005 Stock Incentive Plan (incorporated herein by reference to Appendix A to Superior Energy Services, Inc. s Definitive Proxy Statement filed April 19, 2005 (File No. 333-22603)).
10.10^	Amended and Restated Superior Energy Services, Inc. 2004 Directors Restricted Stock Units Plan (incorporated herein by reference to Appendix B to Superior Energy Services, Inc. s Definitive Proxy Statement filed April 20, 2006 (File No. 333-22603)).
10.11	Purchase, Contribution and Redemption Agreement, dated February 25, 2008, by and among Dynamic Offshore Resources, LLC, Moreno Group LLC, SESI, L.L.C., and SPN Resources, LLC (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed February 29, 2008 (File No. 333-22603)).
10.12^	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 Superior Energy Services, Inc. s Form 8-K filed March 6, 2008 (File No. 333-22603)).
10.13^	Superior Energy Services, Inc. Supplemental Executive Retirement Plan (incorporated herein by reference to Exhibit 10.21 to Superior Energy Services, Inc. s Annual Report on Form 10-K for the year ended December 31, 2009 (File No. 001-34037)), as amended by Amendment No. 1 to the Superior Energy Supplemental Executive Retirement Plan (incorporated herein by reference to Exhibit 10.21 to Superior Energy Services, Inc. s Form 10-K for the year ended December 31, 2010 (File No. 001-34037)).
10.14^	Superior Energy Services, Inc. 2009 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed May 27, 2009 (File No. 001-34037)).

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Exhibit No.	Description
10.15	Third Amended and Restated Credit Agreement, dated February 7, 2012, among SESI, L.L.C., Superior Energy Services, Inc., JPMorgan Chase Bank, N.A. and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed February 8, 2012 (File No. 001-34037)).
10.16^	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 Superior Energy Services, Inc. s Form 8-K filed December 16, 2009 (File No. 001-34037)).
10.17^	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 10.2 to Superior Energy Services, Inc. s Form 8-K filed December 16, 2009 (File No. 001-34037)).
10.18^	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 10.3 to Superior Energy Services, Inc. s Form 8-K filed December 16, 2009 (File No. 001-34037)).
10.19^	Superior Energy Services, Inc. 2011 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed May 26, 2011 (File No. 001-34037)).
10.20^	Form of Stock Option Agreement under the Superior Energy Services, Inc. 2011 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed December 14, 2011 (File No. 001-34037)).
10.21^	Form of Restricted Stock Agreement under the Superior Energy Services, Inc. 2011 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Superior Energy Services, Inc. s Form 8-K filed December 14, 2011 (File No. 001-34037)).
10.22^	Form of Performance Share Unit Award Agreement under the Superior Energy Services, Inc. 2011 Stock Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Superior Energy Services, Inc. s Form 8-K filed December 14, 2011 (File No. 001-34037)).
10.23*	Complete Production Services, Inc. Amended and Restated 2001 Stock Incentive Plan.
10.24*	Amendment No. 1 to the Complete Production Services, Inc. Amended and Restated 2001 Stock Incentive Plan.
10.25*	Complete Production Services, Inc. 2008 Incentive Award Plan.
10.26*	Amendment No. 1 to the Complete Production Services, Inc. 2008 Incentive Award Plan.
10.27^	Employment Agreement, dated effective as of April 28, 2010, by and between Superior Energy Services, Inc. and David D. Dunlap (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed May 3, 2010 (File No. 001-34037)).
10.28^	Buy-Out Agreement, dated effective as of April 28, 2010, by and between Superior Energy Services, Inc. and Terence E. Hall (incorporated herein by reference to Exhibit 10.3 to Superior Energy Services, Inc. s Form 8-K filed May 3, 2010 (File No. 001-34037)).
10.29^	Senior Advisor Agreement, dated effective as of May 20, 2011, by and between Superior Energy Services, Inc. and Terence E. Hall (incorporated herein by reference to Exhibit 10.4 to Superior Energy Services, Inc. s Form 8-K filed May 3, 2010 (File No. 001-34037)).
10.30^	Senior Advisor Agreement, dated effective as of January 1, 2011, by and between Superior Energy Services, Inc. and Kenneth L. Blanchard (incorporated herein by reference to Exhibit 10.5 to Superior Energy Services, Inc. s Form 8-K filed May 3, 2010 (File No. 001-34037)).

Exhibit No.	Description
10.31^	Letter Agreement, dated effective December 10, 2010, by and between Superior Energy Services, Inc. and Terence E. Hall (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed December 16, 2010 (File No. 001-34037)).
10.32^	Letter Agreement, dated effective December 10, 2010, by and between Superior Energy Services, Inc. and Kenneth L. Blanchard (incorporated herein by reference to Exhibit 10.2 to Superior Energy Services, Inc. s Form 8-K filed December 16, 2010 (File No. 001-34037)).
10.33^*	Employment Agreement, dated June 1, 2007, between Superior Energy Services, Inc. and Gregory A. Rosenstein.
10.34^*	Amended and Restated Complete Production Services, Inc. Executive Agreement, dated December 31, 2008, between Complete Production Services, Inc. and Brian K. Moore.
10.35^	Superior Energy Services, Inc. Directors Deferred Compensation Plan (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed February 25, 2011 (File No. 001-34037)).
10.36	Purchase Agreement dated April 20, 2011, with respect to SESI, L.L.C. s $500,000,000 6.375% Senior Notes due 2019 (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed April 26, 2011 (File No. 001-34037)).
10.37	Registration Rights Agreement dated April 27, 2011, by and among SESI, L.L.C., Superior Energy Services, Inc., the guarantors listed in Schedule 1 thereto and J.P. Morgan Securities LLC (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed April 27, 2011 (File No. 001-34037)).
10.38	Purchase Agreement dated November 21, 2011, with respect to SESI, L.L.C. s $800,000,000 7.125% Senior Notes due 2021 (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed November 28, 2011 (File No. 001-34037)).
10.39	Registration Rights Agreement dated December 6, 2011, by and among SESI, L.L.C., Superior Energy Services, Inc., the guarantors listed in Schedule 1 thereto and J.P. Morgan Securities LLC (incorporated herein by reference to Exhibit 10.1 to Superior Energy Services, Inc. s Form 8-K filed December 12, 2011 (File No. 001-34037)).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
14.1	Code of Business Ethics and Conduct (incorporated herein by reference to Exhibit 14.1 to Superior Energy Services, Inc. s Form 8-K filed on February 25, 2011 (File No. 001-34037)).
21.1*	Subsidiaries of Superior Energy Services, Inc.
23.1*	Consent of KPMG LLP, independent registered public accounting firm.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
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.
99.1*	Appraisal Report as of December 31, 2011 on Certain Properties owned by Superior Energy Services, Inc.
101.INS**	XBRL Instance Document

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Exhibit No.	Description
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document

* Filed herein
** Furnished with this Form 10-K
^ 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 28, 2012

By: /s/ DAVID D. DUNLAP
David D. Dunlap
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/ DAVID D. DUNLAP **David D. Dunlap**	Chief Executive Officer (Principal Executive Officer)	February 28, 2012
/s/ ROBERT S. TAYLOR **Robert S. Taylor**	Executive Vice President, Treasurer and Chief Financial Officer (Principal Financial and Accounting Officer)	February 28, 2012
/s/ TERENCE E. HALL **Terence E. Hall**	Chairman of the Board	February 28, 2012
/s/ HAROLD J. BOUILLION **Harold J. Bouillion**	Director	February 28, 2012
/s/ ENOCH L. DAWKINS **Enoch L. Dawkins**	Director	February 28, 2012
/s/ JAMES M. FUNK **James M. Funk**	Director	February 28, 2012
/s/ ERNEST E. HOWARD, III **Ernest E. Howard, III**	Director	February 28, 2012
/s/ PETER D. KINNEAR **Peter D. Kinnear**	Director	February 28, 2012
/s/ MICHAEL M. MCSHANE	Director	February 28, 2012

Michael M. McShane		
/s/ W. MATT RALLS	Director	February 28, 2012
W. Matt Ralls		
/s/ JUSTIN L. SULLIVAN	Director	February 28, 2012
Justin L. Sullivan		

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SCHEDULE Valuation and Qualifying Accounts

SUPERIOR ENERGY SERVICES, INC. AND SUBSIDIARIES

Schedule II Valuation and Qualifying Accounts

Years Ended December 31, 2011, 2010 and 2009

(in thousands)

Description	Balance at the beginning of the year	Charged to costs and expenses	Deductions	Balance at the end of the year
Year ended December 31, 2011:				
Allowance for doubtful accounts	$ 22,618	$ 3,689	$ 8,823	$ 17,484
Year ended December 31, 2010:				
Allowance for doubtful accounts	$ 23,679	$ 4,825	$ 5,886	$ 22,618
Year ended December 31, 2009:				
Allowance for doubtful accounts	$ 18,013	$ 10,866	$ 5,200	$ 23,679

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