BASIC ENERGY SERVICES INC
Form 10-K
February 24, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2013

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number 001-32693

Basic Energy Services, Inc.

(Exact name of registrant as specified in its charter)

Delaware	54-2091194
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 Cherry Street, Suite 2100	
Fort Worth, Texas	76102
(Address of principal executive offices)	(Zip code)

Registrant’s telephone number, including area code:

(817) 334-4100

Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Name of each exchange on which registered
Common Stock, $0.01 par value per share	New York Stock Exchange

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

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

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

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

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

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

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

Large Accelerated Filer	Accelerated Filer
Non-Accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

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

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant was approximately $324,117,558 as of June 30, 2013, the last business day of the registrant's most recently completed second fiscal quarter (based on a closing price of $12.09 per share and 26,808,731 shares held by non-affiliates).

There were 42,506,046 shares of the registrant's common stock outstanding as of February 24, 2014.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the registrant’s Annual Meeting of Stockholders (to be filed within 120 days of the close of the registrant’s fiscal year) are incorporated by reference into Part III.

BASIC ENERGY SERVICES, INC.

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CAUTIONARY STATEMENT

REGARDING FORWARD-LOOKING STATEMENTS

This annual report contains certain statements that are, or may be deemed to be, “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. We have based these forward-looking statements largely on our current expectations and projections about future events and financial trends affecting the financial condition of our business. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including, among other things, the risk factors discussed in Item 1A of this annual report and other factors, most of which are beyond our control.

The words “believe,” “estimate,” “expect,” “anticipate,” “project,” “intend,” “plan,” “seek,” “could,” “should,” “may,” “potent expressions are intended to identify forward-looking statements. All statements other than statements of current or historical fact contained in this annual report are forward looking-statements. Although we believe that the forward-looking statements contained in this annual report are based upon reasonable assumptions, the forward-looking events and circumstances discussed in this annual report may not occur and actual results could differ materially from those anticipated or implied in the forward-looking statements.

Important factors that may affect our expectations, estimates or projections include:

•a decline in, or substantial volatility of, oil and natural gas prices, and any related changes in expenditures by our customers;

•competition within our industry;

•the effects of future acquisitions on our business;

•our access to capital on favorable terms;

•changes in customer requirements in markets or industries we serve;

•general economic and market conditions;

•our ability to replace or add workers at economic rates; and

•environmental and other governmental regulations.

Our forward-looking statements speak only as of the date of this annual report. Unless otherwise required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

This annual report includes market share data, industry data and forecasts that we obtained from internal company surveys (including estimates based on our knowledge and experience in the industry in which we operate), market research, consultant surveys, publicly available information, industry publications and surveys. These sources include Baker Hughes Incorporated, the Association of Energy Service Companies (“AESC”), and the Energy Information Administration of the U.S. Department of Energy (“EIA”). Industry surveys and publications, consultant surveys and forecasts generally state that the information contained therein has been obtained from sources believed to be reliable. Although we believe such information is accurate and reliable, we have not independently verified any of the data from third party sources cited or used for our management’s industry estimates, nor have we ascertained the underlying economic assumptions relied upon therein. For example, the number of onshore well servicing rigs in the U.S. could be lower than our estimate to the extent our two larger competitors have continued to report as stacked rigs equipment that is not actually complete or subject to refurbishment. Statements as to our position relative to our competitors or as to market share refer to the most recent available data.

PART I

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

General

We provide a wide range of well site services in the United States to oil and natural gas drilling and producing companies, including completion and remedial services, fluid services, well servicing and contract drilling. These services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life of a well. Our broad range of services enables us to meet multiple needs of our customers at the well site. We were organized in 1992 as Sierra Well Service, Inc., a Delaware corporation, and in 2000 we changed our name to Basic Energy Services, Inc.

Our operations are managed regionally and are concentrated in major United States onshore oil and natural gas producing regions located in Texas, New Mexico, Oklahoma, Arkansas, Kansas, Louisiana, Wyoming, North Dakota, Colorado, Utah, Montana, West Virginia, Kentucky, Ohio and Pennsylvania. Our operations are focused on liquids-rich basins that currently exhibit strong drilling and production economics as well as natural gas-focused shale plays characterized by prolific reserves and attractive economics. Specifically, we have a significant presence in the Permian Basin and the Bakken, Eagle Ford, Haynesville and Marcellus shales. We provide our services to a diverse group of over 2,000 oil and gas companies.

Our current operating segments are Completion and Remedial Services, Fluid Services, Well Servicing, and Contract Drilling. These segments were selected based on management’s resource allocation and performance assessment in making decisions regarding the Company. The following is a description of our business segments:

•Completion and Remedial Services. Our completion and remedial services segment (40% of our revenues in 2013) operates our fleet of pumping units, an array of specialized rental equipment and fishing tools, coiled tubing units, snubbing units, thru-tubing, air compressor packages specially configured for underbalanced drilling operations, cased-hole wireline units and nitrogen units. The largest portion of this business segment consists of pumping services focused on cementing, acidizing and fracturing services in niche markets.

•Fluid Services. Our fluid services segment (27% of our revenues in 2013) utilizes our fleet of 1,003 fluid service trucks and related assets, including specialized tank trucks, storage tanks, water wells, disposal facilities, water treatment and construction and other related equipment. These assets provide, transport, store and dispose of a variety of fluids, as well as provide well site construction and maintenance services. These services are required in most workover, completion and remedial projects and are routinely used in daily producing well operations.

•Well Servicing. Our well servicing segment (29% of our revenues in 2013) operates our fleet of 425 well servicing rigs and related equipment. This business segment encompasses a full range of services performed with a mobile well servicing rig, including the installation and removal of downhole equipment and elimination of obstructions in the well bore to facilitate the flow of oil and natural gas. These services are performed to establish, maintain and improve production throughout the productive life of an oil and natural gas well and to plug and abandon a well at the end of its productive life. Our well servicing equipment and capabilities also facilitate most other services performed on a well.

•Contract Drilling. Our contract drilling segment (4% of our revenues in 2013) operates our fleet of 12 drilling rigs and related equipment. We use these assets to penetrate the earth to a desired depth and initiate production from a well.

Financial information about our segments is included in Note 15 of the notes to our historical consolidated financial statements.

Our Competitive Strengths

We believe that the following competitive strengths currently position us well within our industry:

Extensive Domestic Footprint in the Most Prolific Basins. Our operations are focused on liquids-rich basins located in the United States that currently exhibit strong drilling and production economics as well as natural gas-focused shale plays characterized by prolific reserves and attractive economics. Specifically, we have a significant presence in the Permian Basin and the Bakken, Eagle Ford, Haynesville and Marcellus shales. Based on the most recent publicly available information, we operate in states that accounted for approximately 78% of the approximately 800,000 existing onshore oil and natural gas wells in the 48 contiguous states and approximately 84% of U.S. onshore oil production and 95% of U.S. onshore natural gas production. We believe that our operations are located in the most active U.S. well services markets, as we currently focus our operations on onshore domestic oil and natural gas production areas that include both the highest concentration of existing oil and natural gas production activities and the largest prospective acreage for new drilling activity. We believe our extensive footprint allows us to offer our suite of services to more than 2,000 customers who are active in those areas and allows us to redeploy equipment between markets as activity shifts, reducing the risk that a basin-specific slowdown will have a disproportionate impact on our cash flows and operational results.

Diversified Service Offering for Further Revenue Growth and Reduced Volatility. We believe our range of well site services provides us a competitive advantage over smaller companies that typically offer fewer services. Our experience, equipment and network of 157 area offices position us to market our full range of well site services to our existing customers. By utilizing a wider range of our services, our customers can use fewer service providers, which enables them to reduce their administrative costs and simplify their logistics. Furthermore, offering a broader range of services allows us to capitalize on our existing customer base and management structure to grow within existing markets, generate more business from existing customers, and increase our operating profits as we spread our overhead costs over a larger revenue base.

Significant Market Position. We maintain a significant market share for each of our lines of business within our core operating areas: the Permian Basin of West Texas and Southeast New Mexico; the Gulf Coast region of South Texas and Louisiana; the Mid-Continent region of North Texas, Oklahoma and Kansas; the Ark-La-Tex region of East Texas, North Louisiana and Arkansas; and the Rocky Mountain region of North New Mexico, Colorado, Utah, Wyoming, Montana and North Dakota. Our goal is to be one of the top two providers of the services we provide in each of our core operating areas. Our position in each of these markets allows us to expand the range of services performed on a well throughout its life, such as drilling, maintenance, workover, stimulation, completion and plugging and abandonment services.

Modern and Competitive Fleet. We operate a modern fleet matched to the needs of the local markets in each of our business segments. We are driven by a desire to maintain one of the most efficient, reliable and safest fleets of equipment in the country, and we have an established program to routinely monitor and evaluate the condition of our equipment. We selectively refurbish equipment to maintain the quality of our service and to provide a safe working environment for our personnel. Since 2003, we have obtained annual independent reviews and evaluations of substantially all of our assets, which confirmed the location and condition of these assets. We believe that by maintaining a modern and active asset base, we are better able to earn our customers' business while reducing the risk of potential downtime.

Decentralized Experienced Management with Strong Corporate Infrastructure. Our corporate group is responsible for maintaining a unified infrastructure to support our diversified operations through standardized financial and accounting, safety, environmental and maintenance processes and controls. Below our corporate level, we operate a decentralized operational organization in which our nine regional or division managers are responsible for their operations, including asset management, cost control, policy compliance and training and other aspects of quality control. With the majority having over 30 years of industry experience, each regional manager has extensive knowledge of the customer base, job requirements and working conditions in each local market. Below our nine regional or division managers, our area managers are directly responsible for customer relationships, personnel management, accident prevention and equipment maintenance, the key drivers of our operating profitability. This management structure allows us to monitor operating performance on a daily basis, maintain financial, accounting and asset management controls, integrate acquisitions, prepare timely financial reports and manage contractual risk.

Our Business Strategy

The key components of our business strategy include:

Establishing and Maintaining Leadership Positions in Core Operating Areas. We strive to establish and maintain market leadership positions within our core operating areas. To achieve this goal, we maintain close customer relationships, seek to expand the breadth of our services and offer high quality services and equipment that meet the scope of customer specifications and requirements. In addition, our significant presence in our core operating areas facilitates employee retention and attraction, a key factor for success in our business. Our significant presence in our core operating areas also provides us with brand recognition that we intend to utilize in creating leading positions in new operating areas.

Selectively Expanding Within Our Regional Markets. We intend to continue strengthening our presence within our existing geographic footprint through internal growth and acquisitions of businesses with strong customer relationships, well-maintained equipment and experienced and skilled personnel. We typically enter into new markets through the acquisition of businesses with strong management teams that will allow us to expand within these markets. Management of acquired companies often remain with us and retain key positions within our organization, which enhances our attractiveness as an acquisition partner. We have a record of successfully implementing this strategy. By concentrating on targeted expansion in areas in which we already have a meaningful presence, we believe we maximize the returns on expansion capital while reducing downside risk.

Developing Additional Service Offerings Within the Well Servicing Market. We intend to continue broadening the portfolio of services we provide to our clients by utilizing our well servicing infrastructure. A customer typically begins a new maintenance or workover project by securing access to a well servicing rig, which generally stays on site for the duration of the project. As a result, our rigs are often the first equipment to arrive at the well site and typically the last to leave, providing us the opportunity to offer our customers other complementary services. We believe the fragmented nature of the well servicing market creates an opportunity to sell more services to our core customers and to expand our total service offering within each of our markets. We have expanded our suite of services available to our customers and increased our opportunities to cross-sell new services to our core well servicing customers through acquisitions and internal growth. We expect to continue to develop or selectively acquire capabilities to provide additional services to expand and further strengthen our customer relationships.

Pursuing Growth Through Selective Capital Deployment. We intend to continue growing our business through selective acquisitions, continuing a newbuild program and/or upgrading our existing assets. Our capital investment decisions are determined by an analysis of the projected return on capital employed of each of those alternatives. Acquisitions are evaluated for “fit” with our area and regional operations management and are reviewed by corporate level financial, equipment, safety and environmental specialists to ensure consideration is given to identified risks. We also evaluate the cost to acquire existing assets from a third party, the capital required to build new equipment and the point in the oil and natural gas commodity price cycle. Based on these factors, we make capital investment decisions that we believe will support our long-term growth strategy, and these decisions may involve a combination of asset acquisitions and the purchase of new equipment.

General Industry Overview

Demand for services offered by our industry is a function of our customers' willingness to make operating and capital expenditures to explore for, develop and produce hydrocarbons in the United States, which in turn is affected by current and expected levels of oil and natural gas prices. Oil prices remained relatively stable through the latter half of 2010, which resulted in increases in drilling, maintenance and workover activities in the oil-driven markets during this period. However, natural gas prices continued to decline significantly in 2009 and remained depressed through 2013, which resulted in decreased activity in the natural gas-driven markets. Oil prices increased during the first half of 2011 primarily due to political and economic instability in several oil producing countries and remained relatively stable through 2013. Despite natural gas prices remaining below the levels seen in past years, several markets that produce significant natural gas liquids, such as the Eagle Ford shale, and/or that have other advantages like proximity to key consuming markets, such as the Marcellus shale, have continued to see stable activity.

The table below sets forth average closing prices for the Cushing WTI Spot Oil Price and the Henry Hub Natural Gas Spot Price since 2011:

Period	Cushing WTI Spot Oil Price ($/bbl)	Henry Hub Gas Spot Price ($/mcf)
1/1/11 - 12/31/11	$ 94.87	$ 4.00
1/1/12 - 12/31/12	94.11	2.75
1/1/13 - 12/31/13	97.91	3.73

Source: U.S. Department of Energy.

Increased expenditures for exploration and production activities generally drive the increased demand for our services. In 2011, oil and natural gas prices improved further and the land-based drilling rig count increased approximately 18%. In 2012, oil prices remained stable and natural gas prices decreased and the land-based drilling rig count decreased approximately 12%, according to the Baker Hughes rig count. In 2013, oil prices remained stable and natural gas prices increased incrementally, and the average oil-based drilling rig count also remained stable. Average natural gas-focused drilling rig count decreased 24% from 2012 to 2013, both according to the Baker Hughes rig count.

Exploration and production spending is generally categorized as either an operating expenditure or a capital expenditure. Activities designed to add hydrocarbon reserves are classified as capital expenditures, while those associated with maintaining or accelerating production are categorized as operating expenditures.

Capital expenditures by oil and gas companies tend to be relatively sensitive to volatility in oil or natural gas prices because project decisions are tied to a return on investment spanning a number of years. As such, capital expenditure economics often require the use of commodity price forecasts which may prove inaccurate in the amount of time required to plan and execute a capital expenditure project (such as the drilling of a deep well). When commodity prices are depressed for even a short period of time, capital expenditure projects are routinely deferred until prices return to an acceptable level.

In contrast, both mandatory and discretionary operating expenditures are substantially more stable than exploration and drilling expenditures. Mandatory operating expenditure projects involve activities that cannot be avoided in the short term, such as regulatory compliance, safety, contractual obligations and projects to maintain the well and related infrastructure in operating condition (for example, repairs to a central tank battery, downhole pump, saltwater disposal system or gathering system). Discretionary operating expenditure projects may not be critical to the short-term viability of a lease or field, but these projects are relatively insensitive to commodity price volatility. Discretionary operating expenditure work is evaluated according to a simple short-term payout criterion that is far less dependent on commodity price forecasts.

Our business is influenced substantially by both operating and capital expenditures by oil and gas companies. Because existing oil and natural gas wells require ongoing spending to maintain production, expenditures by oil and gas companies for the maintenance of existing wells are relatively stable and predictable. In contrast, capital expenditures by oil and gas companies for exploration and drilling are more directly influenced by current and expected oil and natural gas prices and generally reflect the volatility of commodity prices. We believe our focus on production and workover activity partially insulates our financial results from the volatility of the active drilling rig count.

Overview of Our Segments and Services

Completion and Remedial Services Segment

Our completion and remedial services segment provides oil and natural gas operators with a package of services that include the following:

•pumping services, such as cementing, acidizing, fracturing, nitrogen and pressure testing;

•rental and fishing tools;

•coiled tubing;

•snubbing services;

•thru-tubing;

•cased-hole wireline services; and

•underbalanced drilling in low pressure and fluid sensitive reservoirs.

This segment has expanded significantly since 2010, primarily through the acquisition of the Maverick Companies in July 2011. This segment operates 232 pumping units, with approximately 297,000 of horsepower capacity, to conduct a variety of services designed to stimulate oil and natural gas production or to enable cement slurry to be placed in or circulated within a well. We also operate 41 air compressor packages, including foam circulation units, for underbalanced drilling, 37 snubbing units, 14 coiled tubing units and 12 wireline units for cased-hole measurement and pipe recovery services.

Just as a well servicing rig is required to perform various operations over the life cycle of a well, there is a similar need for equipment capable of pumping fluids into the well under varying degrees of pressure. During the drilling and completion phase, the well bore is lined with large diameter steel pipe called casing. Casing is cemented into place by circulating slurry into the annulus created between the pipe and the rock wall of the well bore. The cement slurry is forced into the well by pumping equipment located on the surface. Cementing services are also utilized over the life of a well to repair leaks in the casing, to close perforations that are no longer productive and ultimately to “plug” the well at the end of its productive life.

A hydrocarbon reservoir is essentially an interval of rock that is saturated with oil and/or natural gas, usually in combination with water. Three primary factors determine the productivity of a well that intersects a hydrocarbon reservoir: porosity (the percentage of the reservoir volume represented by pore space in which the hydrocarbons reside), permeability (the natural propensity for the flow of hydrocarbons toward the well bore), and “skin” (the degree to which the portion of the reservoir in close proximity to the well bore has experienced reduced permeability as a result of exposure to drilling fluids or other contaminants). Well productivity can be increased by artificially improving either permeability or skin through stimulation methods described below.

Permeability can be increased through the use of fracturing methods by which a reservoir is subjected to fluids pumped into it under high pressure. This pressure creates stress in the reservoir and causes the rock to fracture, thereby creating additional channels through which hydrocarbons can flow. In most cases, sand or another form of proppant is pumped with the fluid as a means of holding open the newly created fractures.

The most common means of reducing near-well bore damage, or skin, is the injection of a highly reactive solvent (such as hydrochloric acid) solution into the area where the hydrocarbons enter the well. This solution has the effect of dissolving contaminants that have accumulated and are restricting the flow of hydrocarbons. This process is generically known as acidizing.

After a well is drilled and completed, the casing may develop leaks as a result of abrasions from production tubing, exposure to corrosive elements or inadequate support from the original attempt to cement the casing in place. When a leak develops, it is necessary to place specialized equipment into the well and to pump cement in such a way as to seal the leak, a process known as “squeeze” cementing.

The following table sets forth the type, number and location of the completion and remedial services equipment that we operated at December 31, 2013:

	Market Area						
	Ark-La-Tex	Mid-Continent	Gulf Coast	Rocky Mountain	Permian Basin	Appalachia	Total
Pumping Units	10	140	-	43	39	-	232
Air/Foam Packages	-	6	-	29	6	-	41
Snubbing Units	17	10	-	-	-	10	37
Rental and Fishing Tool Stores	-	6	1	4	11	1	23
Coiled Tubing Units	-	2	-	9	3	-	14
Wireline Units	-	7	-	-	5	-	12

Our pumping services business focuses primarily on lower horsepower cementing, acidizing and fracturing services markets. Currently, there are several pumping companies that provide their services on a national basis. For the most part, these companies have concentrated their assets in markets characterized by complex work with higher horsepower requirements. This has created an opportunity in the markets for pumping services in mature areas with less complex characteristics and lower horsepower requirements. We, along with a number of smaller, regional companies, have concentrated our efforts on these markets. One of our major well servicing competitors also participates in the pumping business, but primarily outside our core areas of operations for pumping services.

The level of activity of our pumping services business is tied to drilling and workover activity. The bulk of pumping work is associated with cementing casing in place as the well is drilled or pumping fluid that stimulates production from the well during the completion phase. Pumping service work is awarded based on a combination of price and expertise.

Our rental and fishing tool business provides a range of specialized services and equipment that is utilized on a non-routine basis for both drilling and well servicing operations. Drilling and well servicing rigs are equipped with an array of tools to complete routine operations under normal conditions for most projects in the geographic area in which they are employed. When downhole problems develop with drilling or servicing operations or conditions require non-routine equipment, our customers will usually rely on a provider of rental and fishing tools to augment equipment that is provided with a typical drilling or well servicing rig package.

The term “fishing” applies to a wide variety of downhole operations designed to correct a problem that has developed during the drilling or servicing of a well. The problem most commonly involves equipment that has become lodged in the well and cannot be removed without special equipment. Our technicians utilize tools that are specifically suited to retrieve, or “fish,” and remove the trapped equipment, allowing our customers to resume operations.

Coiled tubing services involve the use of a continuous metal pipe spooled on a large reel for oil and natural gas well interventions, including wellbore maintenance, nitrogen services, thru-tubing services, and formation stimulation using acid and other chemicals.

Snubbing is the act of putting drill pipe into the wellbore when the blowout preventors are closed and pressure is contained in the well. Due to the large rigup, it is only used for the most demanding of operations when lighter intervention techniques do not offer the strength and durability. Unlike conventional drilling and completions operations, snubbing can be performed with the well still under pressure.

Cased-hole wireline services typically utilize a single truck equipped with a spool of wireline that is used to lower and raise a variety of specialized tools in and out of a cased wellbore. These tools can be used to measure pressures and temperature as well as the condition of the casing and the cement that holds the casing in place. Other applications for wireline tools include placing equipment in or retrieving equipment from the wellbore, or perforating the casing and cutting off pipe that is stuck in the well so that the free section can be recovered. Electric wireline contains a conduit that allows signals to be transmitted to or from tools located in the well. A simpler form of wireline, slickline, lacks an electrical conduit and is used only to perform mechanical tasks such as setting or retrieving various tools. Wireline trucks are often used in place of a well servicing rig when there is no requirement to remove tubulars from the well in order to make repairs. Wireline trucks, like well servicing rigs, are utilized throughout the life of a well.

Unlike pumping and wireline services, underbalanced drilling services are not utilized universally throughout oil and natural gas operations. Underbalanced drilling is a technique that involves maintaining the pressure in a well at or slightly below that of the surrounding formation using air, nitrogen, mist, foam or lightweight drilling fluids instead of conventional drilling fluid. The most common method of reducing the weight of drilling fluid is to mix it with air as the fluid is pumped into the well. By varying the volume of air pumped with the fluid, the net hydrostatic pressure can be adjusted to the desired level. In extreme cases, air alone can be used to circulate rock cuttings from the well.

Fluid Services Segment

Our fluid services segment provides oilfield fluid supply, transportation, storage and construction services. These services are required in most workover, completion and remedial projects and are routinely used in daily producing well operations. These services include:

- the transportation of fluids used in drilling and workover operations and of salt water produced as a by-product of oil and natural gas production;
- the sale and transportation of fresh and brine water used in drilling and workover activities;
- the rental of portable frac tanks and test tanks used to store fluids on well sites;
- the recycling and treatment of wastewater, including produced water and flowback, to be reused in the completion and production process;
- the operation of company-owned fresh water and brine source wells and of non-hazardous wastewater disposal wells; and
- the preparation, construction and maintenance of access roads, drilling locations, and production facilities.

This segment utilizes our fleet of fluid service trucks and related assets, including specialized tank trucks, portable storage tanks, water wells, disposal facilities and related equipment. The following table sets forth the type, number and location of the fluid services equipment that we operated at December 31, 2013:

	Market Area					
	Rocky Mountain	Permian Basin	Ark-La-Tex	Mid-Continent	Gulf Coast	Total
Fluid Service Trucks	140	458	180	69	156	1,003
Salt Water Disposal Wells	5	31	24	10	11	81
Fresh/Brine Water Stations	2	38	-	-	4	44
Fluid Storage Tanks	766	1,201	776	278	430	3,451

Requirements for minor or incidental fluid services are usually purchased on a “call out” basis and charged according to a published schedule of rates. Larger projects, such as servicing the requirements of a multi-well drilling program or frac program, generally involve a bidding process. We compete for both services on a call out basis and for multi-well contract projects.

We provide a full array of fluid sales, transportation, storage, treatment and disposal services required on most workover, completion and remedial projects. Our breadth of capabilities in this segment allows us to serve as a one-stop source of equipment and services for our customers. Many of our smaller competitors in this segment can provide some, but not all, of the equipment and services required by oil and gas operators, requiring them to use several companies to meet their requirements and increasing their administrative burden.

Our fluid services segment has a base level of business volume related to the regular maintenance of oil and natural gas wells. Most oil and natural gas fields produce residual salt water in conjunction with oil or natural gas. Fluid service trucks pick up this fluid from tank batteries at the well site and transport it to a salt water disposal well for injection. This type of regular maintenance work must be performed if a well is to remain active. Transportation and disposal of produced water is considered a low value service by most operators, and it is difficult for us to command a premium over rates charged by our competition. Our ability to outperform competitors in this segment depends on our ability to achieve significant economies relating to logistics, specifically the proximity between the areas where salt water is produced and the areas where our company-owned disposal wells are located. We operate salt water disposal wells in most of our markets, and our ownership of these disposal wells eliminates the need to pay third parties a fee for disposal.

Workover, completion and remedial activities also provide the opportunity for higher operating margins from tank rentals and fluid sales. Drilling and workover jobs typically require fresh or brine water for drilling mud or circulating fluid used during the job. Completion and workover procedures often also require large volumes of water for fracturing operations, which involves stimulating a well hydraulically to increase production. Spent mud and flowback fluids from drilling and completion activities are required to be transported from the well site to an approved disposal facility. Water treatment solutions are also utilized by customers to treat produced water and flowback, in order to be reused during the production and completion process.

Our competitors in the fluid services industry are mostly small, regionally focused companies. There are currently no companies that have a dominant position on a nationwide basis. The level of activity in the fluid services industry is comprised of a relatively stable demand for services related to the maintenance of producing wells and a highly variable demand for services used in the drilling and completion of new wells. As a result, the level of onshore drilling activity significantly affects the level of activity in the fluid services industry. While there are no industry-wide statistics, the Baker Hughes Land Drilling Rig Count is an indirect indication of demand for fluid services because it directly reflects the level of onshore drilling activity.

Fluid Services. At December 31, 2013, we owned and operated 1,003 fluid service trucks equipped with an average fluid hauling capacity of up to 150 barrels apiece. Each fluid service truck is equipped to pump fluids from or into wells, pits, tanks and other storage facilities. The majority of our fluid service trucks are also used to transport water to fill frac tanks on well locations, including frac tanks provided by us and others, to transport produced salt water to disposal wells, including injection wells owned and operated by us, and to transport drilling and completion fluids to and from well locations. In conjunction with the rental of our frac tanks, we generally use our fluid service trucks to transport water for use in fracturing operations. Following completion of fracturing operations, our fluid service trucks are used to transport the flowback produced as a result of the fracturing operations from the well site to disposal wells. Fluid service trucks are generally provided to oilfield operators within a 50-mile radius of our nearest yard.

Salt Water Disposal Well Services. We own disposal wells that are permitted to dispose of salt water and incidental non-hazardous oil and natural gas wastes. Our fluid service trucks frequently transport the fluids that are disposed of in these salt water disposal wells. Our disposal wells have an average permitted injection capacity of over 6,000 barrels per day per well and are strategically located in close proximity to our customers’ producing wells. Most oil and natural gas wells produce varying amounts of salt water throughout their productive lives. In the states in which we operate, oil and natural gas wastes and salt water produced from oil and natural gas wells are required by law to be disposed of in authorized facilities, including permitted salt water disposal wells.

Injection wells are licensed by state authorities and are completed in permeable formations below the fresh water table. We maintain separators at most of our disposal wells, allowing us to salvage residual crude oil that we later sell for our account.

Fresh and Brine Water Stations. Our network of fresh and brine water stations, particularly in the Permian Basin where surface water is generally not available, is used to supply water necessary for the drilling and completion of oil and natural gas wells. Our strategic locations, in combination with our other fluid handling services, give us a competitive advantage over other service providers in those areas in which these other companies cannot provide these services.

Fluid Storage Tanks. Our fluid storage tanks can store up to 500 barrels of fluid and are used by oilfield operators to store various fluids at the well site, including fresh water, brine and acid for frac jobs, flowback, temporary production and mud storage. We transport the tanks on our trucks to well locations that are usually within a 50-mile radius of our nearest yard. Frac tanks are used during all phases of the life of a producing well. We generally rent fluid services tanks at daily rates for a minimum of three days. A typical fracturing operation can be completed within four days using 5 to 50 frac tanks.

Water Treatment Services. We utilize a number of water treatment methods in order to treat produced water and flowback that is transported to one of several treatment locations throughout our geographic footprint. Treated water is then sold to customers to be reused as frac water or other oil and gas-related uses on wells. We typically charge for these services on a per-barrel basis.

Construction Services. We utilize a fleet of power units, including dozers, trenchers, motor graders, backhoes and other heavy equipment used in road construction. In addition, we own rock pits in some markets in our Rocky Mountain operations to ensure a reliable source of rock to support our construction activities. Contracts for well site construction services are normally awarded by our customers on the basis of competitive bidding and may range in scope from several days to several months in duration.

Well Servicing Segment

Our well servicing segment encompasses a full range of services performed with a mobile well servicing rig, also commonly referred to as a workover rig, and ancillary equipment. Our rigs and personnel provide the means for hoisting equipment and tools into and out of the well bore, and our well servicing equipment and capabilities also facilitate most other services performed on a well. Our well servicing segment services, which are performed to maintain and improve production throughout the productive life of an oil and natural gas well, include:

- maintenance work involving removal, repair and replacement of down-hole equipment and returning the well to production after these operations are completed;

- hoisting tools and equipment required by the operation into and out of the well, or removing equipment from the well bore, to facilitate specialized production enhancement and well repair operations performed by other oilfield service companies; and

- plugging and abandonment services when a well has reached the end of its productive life.

Our well servicing segment also includes the manufacturing and sale of new workover rigs through our wholly-owned subsidiary, Taylor Industries, LLC, which we formed in connection with the acquisition of a rig manufacturing business in 2010.

Regardless of the type of work being performed on the well, our personnel and rigs are often the first to arrive at the well site and the last to leave. We generally charge our customers an hourly rate for these services, which rate varies based on a number of considerations including market conditions in each region, the type of rig and ancillary equipment required, and the necessary personnel.

Our fleet included 425 well servicing rigs as of December 31, 2013, including 200 newbuilds since October 2004 and 96 rebuilds since the beginning of 2006. Our well servicing rigs operate from facilities in Texas, Wyoming, Oklahoma, North Dakota, New Mexico, Louisiana, Colorado, Arkansas, Utah, Montana, Kansas, Kentucky, Pennsylvania and West Virginia. Our well servicing rigs are mobile units that generally operate within a radius of approximately 75 to 100 miles from their respective bases. The majority of our well servicing segment consists of land-based equipment. We also own four inland well servicing barges. Inland barges are used to service wells in shallow water marine environments, such as coastal marshes and bays.

The following table sets forth the location, characteristics and number of the well servicing rigs that we operated at December 31, 2013. We categorize our rig fleet by the rated capacity of the mast, which indicates the maximum weight that the rig is capable of lifting. The maximum weight our rigs are capable of lifting is the limiting factor in our ability to provide these services.

		Market Area							
Rig Type	Rated Capacity	Permian Basin	Gulf Coast	Ark-La-Tex	Mid-Continent	Rocky Mountain	Appalachia	Stacked	Total
Swab	N/A	1	1	6	1	-	-	-	9
Light Duty	< 90 tons	3	1	-	5	-	1	9	19
Medium Duty	> 90 <125 tons	112	28	25	36	44	3	17	265
Heavy Duty	> 125 tons	74	15	6	4	14	4	7	124
24-Hour	> 125 tons	2	-	-	-	-	-	2	4
Inland Barge	> 125 tons	-	4	-	-	-	-	-	4
Total		192	49	37	46	58	8	35	425

We operate a total of 425 well servicing rigs, one of the largest fleets in the United States. Based on the most recent publicly available information, four of our competitors operate more than 100 well servicing rigs: Key Energy Services, Nabors Industries, Superior Energy Services and Forbes Energy Services. Excluding the rigs operated by Nabors Industries in California, where we do not compete, we believe we have the second largest well servicing rig fleet in the United States.

Maintenance. Regular maintenance is generally required throughout the life of a well to sustain optimal levels of oil and natural gas production. Regular maintenance currently comprises the largest portion of our work in this segment, and because ongoing maintenance spending is required to sustain production, we generally experience relatively stable demand for these services. We provide well service rigs, equipment and crews to our customers for these maintenance services. Maintenance services are often performed on a series of wells in proximity to each other and consist of routine mechanical repairs necessary to maintain production, such as repairing inoperable pumping equipment in an oil well or replacing defective tubing in a natural gas well, and removing debris such as sand and paraffin from the well. Other services include pulling the rods, tubing, pumps and other downhole equipment out of the well bore to identify and repair a production problem. These downhole equipment failures are typically caused by the repetitive pumping action of an oil well. Corrosion, water cut, grade of oil, sand production and other factors can also result in frequent failures of downhole equipment.

The need for maintenance activity does not directly depend on the level of drilling activity, although it is somewhat impacted by short-term fluctuations in oil and natural gas prices. Demand for our maintenance services is driven primarily by the production requirements of local oil or natural gas fields and is therefore affected by changes in the total number of producing oil and natural gas wells in our geographic service areas.

Our regular well maintenance services involve relatively low-cost, short-duration jobs which are part of normal well operating costs. Well operators cannot delay all maintenance work without a significant impact on production. Operators may, however, choose to shut in producing wells temporarily when oil or natural gas prices are too low to justify additional expenditures, including maintenance.

Workover. In addition to periodic maintenance, producing oil and natural gas wells occasionally require major repairs or modifications called workovers, which are typically more complex and more time consuming than maintenance operations. Workover services include extensions of existing wells to drain new formations either through perforating the well casing to expose additional productive zones not previously produced, deepening well bores to new zones or the drilling of lateral well bores to improve reservoir drainage patterns. Our workover rigs are also used to convert former producing wells to injection wells through which water or carbon dioxide is then pumped into the formation for enhanced oil recovery operations. Workovers also include major subsurface repairs such as repair or replacement of well casing, recovery or replacement of tubing and removal of foreign objects from the well bore. These extensive workover operations are normally performed by a workover rig with additional specialized auxiliary equipment, which may include rotary drilling equipment, mud pumps, mud tanks and fishing tools, depending upon the particular type of workover operation. Most of our well servicing rigs are designed to perform complex workover operations. A workover may require a few days to several weeks and generally requires additional auxiliary equipment. The demand for workover services is sensitive to oil and natural gas producers' intermediate and long-term expectations for oil and natural gas prices. As oil and natural gas prices increase, the level of workover activity tends to increase as oil and natural gas producers seek to increase output by enhancing the efficiency of their wells.

New Well Completion. New well completion services involve the preparation of newly drilled wells for production. The completion process may involve selectively perforating the well casing in the productive zones to allow oil or natural gas to flow into the well bore, stimulating and testing these zones and installing the production string and other downhole equipment. We provide well service rigs to assist in this completion process. Newly drilled wells are frequently completed by well servicing rigs to minimize the use of higher cost drilling rigs in the completion process. The completion process typically requires a few days to several weeks, depending on the nature and type of the completion, and generally requires additional auxiliary equipment. Accordingly, completion services require less well-to-well mobilization of equipment and generally provide higher operating margins than regular maintenance work. The demand for completion services is directly related to drilling activity levels, which are sensitive to expectations relating to and changes in oil and natural gas prices.

Plugging and Abandonment. Well servicing rigs are also used in the process of permanently closing oil and natural gas wells no longer capable of producing in economic quantities. Plugging and abandonment work can be performed with a well servicing rig along with wireline and cementing equipment; however, this service is typically provided by companies that specialize in plugging and abandonment work. Many well operators bid this work on a "turnkey" basis, requiring the service company to perform the entire job, including the sale or disposal of equipment salvaged from the well as part of the compensation received, and comply with state regulatory requirements. Plugging and abandonment work can provide favorable operating margins and is less sensitive to oil and natural gas prices than drilling and workover activity since well operators must plug a well in accordance with state regulations when it is no longer productive. We perform plugging and abandonment work throughout our core areas of operation in conjunction with equipment provided by other service companies.

Contract Drilling Segment

Our contract drilling segment employs drilling rigs and related equipment to penetrate the earth to a desired depth and initiate production.

We own and operate 12 land drilling rigs, which are currently deployed in the Permian Basin of Texas and New Mexico. A land drilling rig generally consists of engines, a drawworks, a mast, pumps to circulate the drilling fluid (mud) under various pressures, blowout preventers, drill string and related equipment. The engines power the different pieces of equipment, including a rotary table or top drive that turns the drill string, causing the drill bit to bore through the subsurface rock layers. These jobs are typically bid by "daywork" contracts, in which an agreed upon rate per day is charged to the customer, or "footage" contracts, in which an agreed upon rate per the number of feet drilled is charged to the customer. The demand for drilling services is highly dependent on the availability of new drilling locations available to well operators, as well as sensitivity to expectations relating to and changes in oil and natural gas prices.

Properties

Our principal executive offices are located at 801 Cherry Street, Suite 2100, Fort Worth, Texas 76102. We currently conduct our business from 157 area offices, 87 of which we own and 70 of which we lease. Each office typically includes a yard, administrative office and maintenance facility. Of our 157 area offices, 96 are located in Texas, 13 are in Oklahoma, 11 are in New Mexico, 9 are in Colorado, 9 are in North Dakota, 6 are in Wyoming, 3 are in Utah, 2 are in Louisiana, 2 are in Arkansas, 2 are in Kansas, 2 are in Montana, 1 is in Ohio, and 1 is in Pennsylvania.

Customers

We serve numerous major and independent oil and gas companies that are active in our core areas of operations. During 2013, no single customer comprised over 10% of our total revenues. The majority of our business is with independent oil and gas companies. While we believe we could redeploy equipment in the current market environment if we lost any material customers, such loss could have an adverse effect on our business until the equipment is redeployed.

Operating Risks and Insurance

Our operations are subject to hazards inherent in the oil and natural gas industry, such as accidents, blowouts, explosions, craterings, fires and oil spills that can cause:

•personal injury or loss of life;

•damage to or destruction of property, equipment and the environment; and

•suspension of operations.

In addition, claims for loss of oil and natural gas production and damage to formations can occur in the well services industry. If a serious accident were to occur at a location where our equipment and services are being used, it could result in our being named as a defendant in lawsuits asserting large claims.

Because our business involves the transportation of heavy equipment and materials, we may also experience traffic accidents which may result in spills, property damage and personal injury.

Despite our efforts to maintain high safety standards, we from time to time have suffered accidents in the past and anticipate that we could experience accidents in the future. In addition to the property and personal losses from these accidents, the frequency and severity of these incidents affect our operating costs and insurability and our relationships with customers, employees and regulatory agencies. Any significant increase in the frequency or severity of these incidents, or the general level of damage awards, could adversely affect the cost of, or our ability to obtain, workers' compensation and other forms of insurance, and could have other material adverse effects on our financial condition and results of operations.

Although we maintain insurance coverage of types and amounts that we believe to be customary in the industry, we are not fully insured against all risks, either because insurance is not available or because of the high premium costs. We do maintain employer's liability, pollution, cargo, umbrella, comprehensive commercial general liability, workers' compensation and limited physical damage insurance. There can be no assurance, however, that any insurance obtained by us will be adequate to cover any losses or liabilities, or that this insurance will continue to be available or available on terms which are acceptable to us. Liabilities for which we are not insured, or which exceed the policy limits of our applicable insurance, could have a material adverse effect on us.

Competition

Our competition includes small regional contractors as well as larger companies with international operations. We believe our two largest competitors, Key Energy Services, Inc. and Nabors Well Services Co., each own a significant number of the U.S. marketable well servicing rigs according to the most recent publicly available data, including the Guiberson-AESC well service rig count. Both Key and Nabors are public companies that operate in most of the large oil and natural gas producing regions in the United States. They each have centralized management teams that direct their operations and decision-making primarily from corporate and regional headquarters. In addition, because of their size, Key and Nabors market a large portion of their work to the major oil and gas companies.

We differentiate ourselves from our major competition by our operating philosophy. We operate a decentralized organization, where local, experienced management teams are largely responsible for sales and operations and developing stronger relationships with our customers at the field level. We target areas that are attractive to independent oil and gas operators who in our opinion tend to be more aggressive in spending, less focused on price and more likely to award work based on performance. We concentrate on providing services to a diverse group of large and small independent oil and gas companies. These independents typically are relationship driven, make decisions at the local level and are willing to pay higher rates for services. We have been successful using this business model and believe it will enable us to continue to grow our business.

Safety Program

Our business involves the operation of heavy and powerful equipment which can result in serious injuries to our employees and third parties and substantial damage to property. We have comprehensive safety and training programs designed to minimize accidents in the workplace and improve the efficiency of our operations. In addition, many of our larger customers now place greater emphasis on safety and quality management programs of their contractors. We believe that these factors will gain further importance in the future. We have directed substantial resources toward employee safety and quality management training programs as well as our employee review process. While our efforts in these areas are not unique, we believe many competitors, and particularly smaller contractors, have not undertaken similar training programs for their employees.

We believe our approach to safety management is consistent with our decentralized management structure. Company-mandated policies and procedures provide the overall framework to ensure our operations minimize the hazards inherent in our work and are intended to meet regulatory requirements, while allowing our operations to satisfy customer-mandated policies and local needs and practices.

Environmental Regulation and Climate Change

Environment, Health and Safety Regulation, Including Climate Change

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, commonly referred to as the “EPA,” and analogous state agencies issue regulations to implement and enforce these laws, which often require stringent and costly compliance measures. These laws and regulations may, among other things, require the acquisition of permits; govern the amounts and types of substances that may be released into the environment in connection with oil and gas drilling; restrict the way we handle or dispose of our materials and wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; or require investigatory and remedial actions to mitigate pollution conditions. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the possible issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose liability for environmental damages and cleanup costs without regard to negligence or fault. Strict adherence with these regulatory requirements increases our cost of doing business and consequently affects our profitability. We believe that we are in substantial compliance with current applicable environmental, health and safety laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. However, environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect upon our capital expenditures, earnings or our competitive position. Below is a discussion of the principal environmental laws and regulations that relate to our business.

The Comprehensive Environmental Response, Compensation and Liability Act, referred to as "CERCLA" or the Superfund law, and comparable state laws impose liability, potentially without regard to fault or legality of the activity at the time, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, neighboring landowners and other third parties may file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as "RCRA," regulates the management and disposal of solid and hazardous waste. Some wastes associated with the exploration and production of oil and natural gas are exempted from the most stringent regulation in certain circumstances, such as drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas. However, these wastes and other wastes may be otherwise regulated by the EPA or state agencies. Moreover, in the ordinary course of our operations, industrial wastes such as paint wastes and waste solvents may be regulated as hazardous waste under RCRA or considered hazardous substances under CERCLA.

We currently own or lease, and have in the past owned or leased, a number of properties that have been used as service yards in support of oil and natural gas exploration and production activities. Although we have utilized operating and disposal practices that we considered standard in the industry at the time, there is the possibility that repair and maintenance activities on rigs and equipment stored in these service yards, as well as fluids stored at these yards, may have resulted in the disposal or release of hydrocarbons or other wastes on or under these yards or other locations where these wastes have been taken for disposal. In addition, we own or lease properties that in the past were operated by third parties whose operations were not under our control. These properties and the hydrocarbons or wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination.

In the course of our operations, some of our equipment may be exposed to naturally occurring radiation associated with oil and natural gas deposits, and this exposure may result in the generation of wastes containing naturally occurring radioactive materials, or "NORM." NORM wastes exhibiting trace levels of naturally occurring radiation in excess of established state standards are subject to special handling and disposal requirements, and any storage vessels, piping and work area affected by NORM may be subject to remediation or restoration requirements. Because many of the properties presently or previously owned, operated or occupied by us have been used for oil and natural gas production operations for many years, it is possible that we may incur costs or liabilities associated with elevated levels of NORM.

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under these laws, permits must be obtained to discharge pollutants into regulated surface or subsurface waters. Spill prevention, control and countermeasure requirements under federal law require appropriate operating protocols, including containment berms and similar structures, to help prevent the contamination of regulated waters in the event of a petroleum hydrocarbon spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities or during construction activities. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Additionally, permits for discharges of storm water runoff may be required for certain of our properties.

The federal Clean Water Act and the federal Oil Pollution Act of 1990 contain numerous requirements relating to the prevention of and response to oil spills into regulated waters, and require some owners or operators of facilities that store or otherwise handle oil to prepare and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," relating to the possible discharge of oil into regulated waters.

Our underground injection operations are subject to the federal Safe Drinking Water Act, referred to as the “SDWA,” as well as analogous state and local laws and regulations including the Underground Injection Control (“UIC”) program, which program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities. The federal Energy Policy Act of 2005 amended the UIC provisions to exclude certain hydraulic fracturing activities from the definition of “underground injection” under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. Similar legislation could be introduced in the current session of Congress, which commenced in January 2014, or at the state level. For example at the state level, several states in which we operate, including Wyoming, Texas, Colorado and Oklahoma, have adopted regulations requiring operators to disclose certain information regarding hydraulic fracturing fluids. Our operations employ hydraulic fracturing techniques to stimulate natural gas production from unconventional geological formations, which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. Our hydraulic fracturing activities are principally in Texas, Oklahoma, Kansas and Colorado. Our operations also involve the disposal of produced salt water by underground injection. The substantial majority of our saltwater disposal wells are located in Texas and are regulated by the Texas Railroad Commission, also known as the “RRC.” We also operate salt water disposal wells in New Mexico, Oklahoma, Arkansas, Louisiana and North Dakota and are subject to similar regulatory controls in those states. Regulations in these states require us to obtain a permit from the applicable regulatory agencies to operate each of our underground salt water disposal wells. We believe that we have obtained the necessary permits from these agencies for each of our underground injection wells and that we are in substantial compliance with permit conditions and commission rules. Nevertheless, these regulatory agencies have the general authority to suspend or modify one or more of these permits if continued operation of one of our underground injection wells is likely to result in pollution of freshwater, substantial violation of permit conditions or applicable rules, or leaks to the environment or other conditions such as earthquakes. Although we monitor the injection process of our wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third parties for property damages and personal injuries. In addition, our sales of residual crude oil collected as part of the saltwater injection process could impose liability on us in the event that the entity to which the oil was transferred fails to manage the residual crude oil in accordance with applicable environmental health and safety laws.

We maintain insurance against some risks associated with environmental liabilities that may occur as a result of well service activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will cover all potential losses, that insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

We are also subject to the requirements of the federal Occupational Safety and Health Act, known as “OSHA,” and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public.

The federal Clean Air Act, as amended, known as the “Clean Air Act,” and state air pollution permitting laws, restrict the emission of air pollutants from many sources, including drilling operations and related equipment, and as a result affect oil and natural gas operations. In addition, more stringent regulations governing emissions of air pollutants, including greenhouse gases such as methane (a component of natural gas) and carbon dioxide (“CO_2”), are being developed by the federal government and may increase the costs of compliance for our drilling services or our customers’ operations. For example, on August 16, 2012, EPA published rules which impose new standards for air emissions from oil and natural gas development and production operations, including requirements to reduce methane emissions, a volatile organic compound as well as a greenhouse gas.

Responding to scientific studies that have suggested that emissions of gases, commonly referred to as “greenhouse gases,” including gases associated with the oil and gas sector such as carbon dioxide, methane, and nitrous oxide among others, may be contributing to global warming and other environmental effects, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In the recent Congress, numerous legislative measures were introduced that would have imposed restrictions or costs on greenhouse gas emissions, including from the oil and gas industry. It is uncertain whether similar measures will be introduced in, or passed by, the new Congress which convened in January 2014. However, any such legislation may have the potential to affect our business, customers or the energy sector generally. In addition, the United States has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change (“UNFCCC”). Other nations have already agreed to regulate emissions of greenhouse gases, pursuant to the UNFCCC and a subsidiary agreement known as the “Kyoto Protocol,” an international treaty pursuant to which participating countries have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. The United States is a party to the

UNFCCC but did not ratify the Kyoto Protocol. Such negotiations have thus far not resulted in substantive changes that would affect domestic industrial sources in the United States, and it is uncertain whether an international agreement will be reached or what the terms of any such agreement would be. The EPA has also taken action under the CAA to regulate greenhouse gas emissions. In addition, some states have taken or proposed legal measures to reduce emissions of greenhouse gases.

Following the U.S. Supreme Court's decision in Massachusetts, et al. v. EPA, 549 U.S. 497 (2007), finding that greenhouse gases fall within the CAA definition of "air pollutant," the EPA determined that greenhouse gases from certain sources "endanger" public health or welfare. The EPA subsequently promulgated certain regulations and interpretations that will require new and modified stationary sources of greenhouse gases above certain thresholds to report, limit or control such emissions. On November 8, 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and gas industry, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, the EPA has taken the position that existing Clean Air Act provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration and Title V permit programs. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost effective. Such changes will also affect state air permitting programs in states that administer the federal CAA under a delegation of authority, including states in which we have operations. Although subject to legal challenge, the EPA rules promulgated thus far are currently final and effective and will remain so unless overturned by a court, or unless Congress adopts legislation altering the EPA's regulatory authority. The EPA published rules setting green completion standards for natural gas wells and has also announced its intention to promulgate additional regulations restricting greenhouse gas emissions, including rules applicable to the power generation sector and oil refining sector.

There is considerable debate as to global warming and the environmental effects of greenhouse gas emissions and associated consequences affecting global climate, oceans, and ecosystems. As a commercial enterprise, we are not in a position to validate or repudiate the existence of global warming or various aspects of the scientific debate. However, if global warming is occurring, it could have an impact on our operations. For example, our operations in low lying areas such as the coastal regions of Louisiana and Texas may be at increased risk due to flooding, rising sea levels or disruption of operations from more frequent and severe weather events. Facilities in areas with limited water availability may be impacted if droughts become more frequent or severe. Changes in climate or weather may hinder exploration and production activities or increase or decrease the cost of production of oil and natural gas resources and consequently affect demand for our field services. Changes in climate or weather may also affect consumer demand for energy or alter the overall energy mix. However, we are not in a position to predict the precise effects of global warming on energy markets or the physical effects of global warming. We are providing this disclosure based on publicly available information on the matter.

Employees

As of December 31, 2013, we employed approximately 5,400 people, with approximately 83% employed on an hourly basis. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements, and we consider our relations with our employees to be satisfactory.

Executive Officers of the Registrant

Our executive officers as of February 24, 2014 and their respective ages and positions are as follows:

Name	Age	Position
Thomas M. “Roe” Patterson	39	President, Chief Executive Officer and Director
Alan Krenek	58	Senior Vice President, Chief Financial Officer, Treasurer and Secretary
James F. Newman	49	Senior Vice President — Region Operations
William T. Dame	53	Vice President — Pumping Services
Douglas B. Rogers	50	Vice President — Marketing
James E. Tyner	63	Vice President — Human Resources
	46	

Lanny T. Poldrack..		Vice President — Safety and Operations Support
John Cody Bissett..	39	Vice President, Controller and Chief Accounting Officer
Brett J. Taylor..	41	Vice President — Equipment and Manufacturing

Set forth below is the description of the backgrounds of our executive officers.

Thomas M. “Roe” Patterson (President, Chief Executive Officer and Director) has 19 years of related industry experience. He was named our President and Chief Executive Officer and appointed as a Director in September 2013. Since joining Basic in 2006, he served in positions of increasing responsibility: as our Senior Vice President and Chief Operating Officer from April 2011 until September 2013, as a Senior Vice President from September 2008 until April 2011 and as a Vice President of various groups within Basic from February 2006 until September 2008. Prior to joining Basic, he was president of his own manufacturing and oilfield service company, TMP Companies, Inc., from 2000 to 2006. He was a Contracts/Sales Manager for the Permian Division of Patterson Drilling Company from 1996 to 2000. He was an Engine Sales Manager for West Texas Caterpillar from 1995 to 1996. Mr. Patterson graduated with a B.S. degree in Biology from Texas Tech University.

Alan Krenek (Senior Vice President, Chief Financial Officer, Treasurer and Secretary) has 26 years of related industry experience. He has been our Vice President, Chief Financial Officer and Treasurer since January 2005. He became Senior Vice President and Secretary in May 2006. Prior to joining Basic, he held various financial management positions at Landmark Graphics Corp., Noble Corporation and Pool Energy Services Company. Mr. Krenek graduated with a B.B.A. degree in Accounting from Texas A&M University and is a Certified Public Accountant.

James F. Newman (Senior Vice President — Regional Operations) has 29 years of related industry experience and has been our Senior Vice President, Region Operations since November 2013. He previously served as our Group Vice President — Permian Business Unit from April 2011 until September 2013 and has been a Group Vice President since September 2008. Prior to joining Basic, he co-founded Triple N Services in 1986 and served as its President through May 2008. He initially served Basic as an Area Manager in the plugging and abandonment operations. Mr. Newman is a registered Professional Engineer and is active in the Society of Professional Engineers. Mr. Newman graduated with a B.S. in Petroleum Engineering from Colorado School of Mines.

William T. Dame (Vice President — Pumping Services) has 33 years of related industry experience. Mr. Dame joined Basic in 2003 and has served as our Vice President — Pumping Services since 2006. He previously served as our Vice President — PPW and RAFT Divisions from 2005 to 2006 and as a regional vice president from 2004 through 2005. Mr. Dame began his career in 1981 with Halliburton. From 1987 to 1997, he served as a vice president of Fleet Cementers, Inc., and from 1997 to 2003, he worked in various operational management positions at Plains Energy, Precision Drilling and New Force Energy Services. Mr. Dame attended Tarleton State University.

Douglas B. Rogers (Vice President — Marketing) has 31 years of related industry experience. He joined Basic in 2007 and serves as Vice President — Marketing after serving as Vice President-Contracts for the Drilling Division. Mr. Rogers was Vice President- Rocky Mountain Division for Patterson - UTI Drilling Company from March 2003 to June 2007. He also served as Western Division Sales Manager for Ambar Lonestar Fluid Services, a division of Patterson - UTI Drilling Company, from 1998 to 2003. He began his career in 1983 with Permian Servicing Company, where he managed well servicing operations. He continued in that capacity through Permian Servicing Company's mergers with Xpert Well Service and Pride Petroleum Service until joining Zia Drill/Nova Mud in March 1997. Mr. Rogers graduated with a B.A. degree from Eastern New Mexico University.

James E. Tyner (Vice President — Human Resources) has been a Vice President since January 2004. From 1999 to June 2003, he was the General Manager of Human Resources at CMS Panhandle Companies, where he directed delivery of HR Services. Mr. Tyner was the Director of Human Resources Administration and Payroll Services at Duke Energy's Gas Transmission Group from 1998 to 1999. From 1981 to 1998, Mr. Tyner held various positions at Panhandle Eastern Corporation. At Panhandle, he managed all Human Resources functions and developed corporate policies and as a Certified Safety Professional, he designed and implemented programs to control workplace hazards. Mr. Tyner received a B.S. in General Science and M.S. in Microbiology from Mississippi State University.

Lanny T. Poldrack (Vice President — Safety and Operations Support) has 27 years of related industry experience. He has served as our Vice President — Safety and Operations Support since April 2011. From April 2009 to April 2011, he served as a Corporate Marketing Representative based in Houston, Texas. Prior to joining Basic, he spent 13 years at Cudd Energy Services where he held various technical sales and sales management positions for both well intervention and live well service divisions, the last 4 years of which he served as Business Development Manager for Cudd Well Control for both domestic and international operations in U.S., Canadian, Latin America, European, Middle Eastern and South East Asian markets. He began his oilfield career in West Texas as a technical field representative for Weatherford International, specializing in fishing and rental tools and hydraulic BOP systems. Mr. Poldrack graduated with an applied science degree from Odessa Junior College.

John Cody Bissett (Vice President, Controller and Chief Accounting Officer) has 12 years of related industry experience. He was appointed Basic's Vice President, Controller and Chief Accounting Officer in March 2012. Mr. Bissett previously served as Basic's Corporate Controller from July 2008 to March 2012 and as the Director of Financial Reporting from December 2007 to July 2008. Prior to joining Basic, Mr. Bissett was the Controller of Cap Rock Energy from November 2006 through December 2007, and previously held various roles in the accounting and finance function of Sirius Computer Solutions and the audit practice of KPMG LLP. Mr. Bissett graduated with an M.B.A. and a B.B.A. in Accounting from Angelo State University and is a Certified Public Accountant.

Brett J. Taylor (Vice President — Manufacturing and Equipment) has 21 years of related industry experience. He has been our Vice President of Manufacturing and Equipment since June 2013. Prior to joining Basic, he was President of Taylor Industries, LLC in Tulsa, Oklahoma from 2010 to 2013. From 2009 to 2010, he served as Executive Vice President of Sales and Marketing at Serva Group Manufacturing. Before that, Mr. Taylor held positions of increasing responsibilities at Taylor Industries over an 11-year span. His tenure at Taylor included the role of Consultant, President of Sales from 2008 to 2009, President of Taylor from 2003 to 2008, General Manager & Vice President of Business Development from 2001 to 2003, and Sales and Marketing Manager from 1997 to 1999. Mr. Taylor graduated with a Bachelor of Business Degree from the University of Oklahoma.

Additional Information

We make available free of charge on our website, www.basicenergyservices.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such information with, or furnish it to, the SEC. These documents are also available on the SEC’s website at www.sec.gov, or you may read and copy any materials that we file with or furnish to the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Washington D.C. 20549. The information on our website is not, and shall not be deemed to be, a part of this annual report on Form 10-K or incorporated into any of our other filings with the SEC.

We have a Code of Conduct that applies to all of our directors, officers and employees. The Code of Conduct is available publicly on our website at www.basicenergyservices.com. Any waivers granted to directors or executive officers and any material amendments to our Code of Conduct will be posted promptly on our website and/or disclosed in a Current Report on Form 8-K.

The certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to this Annual Report on Form 10-K. We have also filed with the New York Stock Exchange the most recent Annual CEO Certification as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

ITEM 1A.RISK FACTORS

The following are some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in our forward-looking statements. We may encounter risks in addition to those described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, may also impair or adversely affect our business, results of operation, financial condition and prospects.

Risks Relating to Our Business

Our business depends on domestic spending by the oil and natural gas industry, and this spending and our business has been in the past, and may in the future be, adversely affected by industry and financial market conditions that are beyond our control.

We depend on our customers' willingness to make operating and capital expenditures to explore for, develop and produce oil and natural gas in the United States. Customers' expectations for lower market prices for oil and natural gas, as well as the availability of capital for operating and capital expenditures, may cause them to curtail spending, thereby reducing demand for our services and equipment.

Industry conditions are influenced by numerous factors over which we have no control, such as the supply of and demand for oil and natural gas, domestic and worldwide economic conditions, political instability in oil and natural gas producing countries and merger and divestiture activity among oil and gas producers. The volatility of the oil and natural gas industry and the consequent impact on exploration and production activity could adversely impact the level of drilling and workover activity by some of our customers. This reduction may cause a decline in the demand for our services or adversely affect the price of our services. In addition, reduced discovery rates of new oil and natural gas reserves in our market areas also may have a negative long-term impact on our business, even in an environment of stronger oil and natural gas prices, to the extent existing production is not replaced and the number of producing wells for us to service declines.

Deterioration in the global economic environment commencing in the latter part of 2008 and continuing throughout 2009 caused the oilfield services industry to cycle into a downturn. The industry returned to higher activity levels in 2011 and remained higher in during the first half of 2012, before another downturn in the second half of 2012 and remained stable in 2013. Adverse changes in capital markets and declines in prices for oil and natural gas experienced during 2008 and 2009 caused many oil and natural gas producers to announce reductions in capital budgets for future periods. Limitations on the availability of capital, or higher costs of capital, for financing expenditures may cause oil and natural gas producers to make reductions to capital budgets in the future even if oil prices remain at current levels or natural gas prices increase from current levels. Any such cuts in spending will curtail drilling programs as well as discretionary spending on well services, which may result in a reduction in the demand for our services, the rates we can charge and our utilization. In addition, certain of our customers could become unable to pay their suppliers, including us. Any of these conditions or events could adversely affect our operating results.

If oil and natural gas prices remain volatile, or if oil prices decline or natural gas prices remain low or decline further, the demand for our services could be adversely affected.

The demand for our services is primarily determined by current and anticipated oil and natural gas prices and the related general production spending and level of drilling activity in the areas in which we have operations. Volatility or weakness in oil prices or natural gas prices (or the perception that oil prices or natural gas prices will decrease) affects the spending patterns of our customers and may result in the drilling of fewer new wells or lower production spending on existing wells. This, in turn, could result in lower demand for our services and may cause lower rates and lower utilization of our well service equipment. If oil prices decline or natural gas prices continue to remain low or decline further, or if there is a reduction in drilling activities, the demand for our services and our results of operations could be materially and adversely affected.

Prices for oil and natural gas historically have been extremely volatile and are expected to continue to be volatile. The Cushing WTI Spot Oil Price averaged $94.87, $94.11 and $ 97.91 per barrel in 2011, 2012 and 2013, respectively, and the Henry Hub Natural Gas Spot Price averaged $4.00, $2.75 and $3.73 per Mcf for 2011, 2012 and 2013, respectively.

Competition within the well services industry may adversely affect our ability to market our services.

The well services industry is highly competitive and fragmented and includes numerous small companies capable of competing effectively in our markets on a local basis, as well as several large companies that possess substantially greater financial and other resources than we do. Our larger competitors’ greater resources could allow those competitors to compete more effectively than we can. The amount of equipment available may exceed demand, which could result in active price competition. Many contracts are awarded on a bid basis, which may further increase competition based primarily on price. In addition, adverse market conditions lower demand for well servicing equipment, which results in excess equipment and lower utilization rates. If market conditions in our oiloriented operating areas were to deteriorate or if adverse market conditions in our natural gas-oriented operating areas persist, utilization rates may decline.

We may require additional capital in the future. We cannot assure you that we will be able to generate sufficient cash internally or obtain alternative sources of capital on favorable terms, if at all. If we are unable to fund capital expenditures, our business may be adversely affected.

We anticipate that we will continue to make substantial capital investments to purchase additional equipment to expand our services, refurbish our well servicing rigs and replace existing equipment. For the year ended December 31, 2013, we invested approximately $137.0 million in cash for capital expenditures, excluding acquisitions. For the year ended December 31, 2012, we invested approximately $171.4 million in cash for capital expenditures, excluding acquisitions. Historically, we have financed these investments through internally generated funds, debt and equity offerings, our capital lease program and borrowing under a senior credit facility. Please read "Liquidity and Capital Resources" for more information.

Our significant capital investments require cash that we could otherwise apply to other business needs. However, if we do not incur these expenditures while our competitors make substantial fleet investments, our market share may decline and our business may be adversely affected. In addition, if we are unable to generate sufficient cash internally or obtain alternative sources of capital to fund our proposed capital expenditures and acquisitions, take advantage of business opportunities or respond to competitive pressures, it could materially adversely affect our results of operations, financial condition and growth. If we raise additional funds by issuing equity securities, dilution to existing stockholders may result. Adverse changes in the capital markets could make it difficult to obtain additional capital or obtain it at attractive rates.

We depend on several significant customers, and a loss of one or more significant customers could adversely affect our results of operations.

Our customers consist primarily of major and independent oil and gas companies. During 2013 and 2012, our top five customers accounted for 27% and 25%, respectively, of our revenues. However, no individual customer composed greater than 10% of our revenues. The loss of any one of our largest customers or a sustained decrease in demand by any of such customers could result in a substantial loss of revenues and could have a material adverse effect on our results of operations.

Our operations are subject to inherent risks, some of which are beyond our control. These risks may be self-insured, or may not be fully covered under our insurance policies.

Our operations are subject to hazards inherent in the oil and natural gas industry, such as, but not limited to, accidents, blowouts, explosions, craterings, fires and oil spills. These conditions can cause:

•personal injury or loss of life;

•damage to or destruction of property, equipment and the environment; and

•suspension of operations.

The occurrence of a significant event or adverse claim in excess of the insurance coverage that we maintain or that is not covered by insurance could have a material adverse effect on our financial condition and results of operations. In addition, claims for loss of oil and natural gas production and damage to formations can occur in the well services industry. Litigation arising from a catastrophic occurrence at a location where our equipment and services are being used may result in our being named as a defendant in lawsuits asserting large claims.

As is customary in our industry, our service contracts generally provide that we will indemnify and hold harmless our customers from any claims arising from personal injury or death of our employees, damage to or loss of our equipment, and pollution emanating from our equipment and services. Similarly, our customers agree to indemnify and hold us harmless from any claims arising from personal injury or death of their employees, damage to or loss of their equipment, and pollution caused from their equipment or the well reservoir (including uncontained oil flow from a reservoir). Our indemnification arrangements may not protect us in every case. For example, from time to time we may enter into contracts with less favorable indemnities or perform work without a contract that protects us. In addition, our indemnification rights may not fully protect us if the customer is insolvent or becomes bankrupt, does not maintain adequate insurance or otherwise does not possess sufficient resources to indemnify us. In addition, our indemnification rights may be held unenforceable in some jurisdictions. Our inability to fully realize the benefits of our contractual indemnification protections could result in significant liabilities and could adversely affect our financial condition, results of operations and cash flows.

Our operations are also subject to the risk of cyber-attacks. If our systems for protecting against cyber security risks prove not to be sufficient, we could be adversely affected by, among other things, loss or damage of intellectual property, proprietary information, or customer data, having our business operations interrupted, and increased costs to prevent, respond to, or mitigate cyber security attacks. These risks could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition.

We maintain insurance coverage that we believe to be customary in the industry against these hazards. However, we do not have insurance against all foreseeable risks, either because insurance is not available or because of the high premium costs. As such, not all of our property is insured. We are also self-insured up to retention limits with regard to workers' compensation, general liability, and medical and dental coverage. We maintain accruals in our consolidated balance sheets related to self-insurance retentions by using third-party data and historical claims history. The occurrence of an event not fully insured against, or the failure of an insurer to meet its insurance obligations, could result in substantial losses. In addition, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. Insurance may not be available to cover any or all of the risks to which we are subject, or, even if available, it may be inadequate, or insurance premiums or other costs could rise significantly in the future so as to make such insurance prohibitively expensive. It is likely that, in our insurance renewals, our premiums and deductibles will be higher, and certain insurance coverage either will be unavailable or considerably more expensive than it has been in the recent past. In addition, our insurance is subject to coverage limits, and some policies exclude coverage for damages resulting from environmental contamination.

We may not be able to grow successfully through future acquisitions or successfully manage future growth, and we may not be able to effectively integrate the businesses we do acquire.

Our business strategy includes growth through the acquisitions of other businesses. We may not be able to continue to identify attractive acquisition opportunities or successfully acquire identified targets. In addition, we may not be successful in integrating our current or future acquisitions into our existing operations, which may result in unforeseen operational difficulties or diminished financial performance or require a disproportionate amount of our management's attention. Even if we are successful in integrating our current or future acquisitions into our existing operations, we may not derive the benefits, such as operational or administrative synergies, that we expected from such acquisitions, which may result in the commitment of our capital resources without the expected returns on such capital. Furthermore, competition for acquisition opportunities may escalate, increasing our cost of making further acquisitions or causing us to refrain from making additional acquisitions. We may also be limited in our ability to incur additional indebtedness in connection with or to fund future acquisitions under the Revolving Credit Facility and under the indentures governing our 7.75% Senior Notes due 2019 and 7.75% Senior Notes due 2022.

Whether we realize the anticipated benefits from an acquisition depends, in part, upon our ability to integrate the operations of the acquired business, the performance of the underlying product and service portfolio, and the performance of the management team and other personnel of the acquired operations. Accordingly, our financial results could be adversely affected from unanticipated performance issues, legacy liabilities, transaction-related charges, amortization of expenses related to intangibles, charges for impairment of long-term assets, credit guarantees, partner performance and indemnifications. While we believe that we have established appropriate and adequate procedures and processes to mitigate these risks, there is no assurance that these transactions will be successful.

Our indebtedness could restrict our operations and make us more vulnerable to adverse economic conditions.

We now have, and will continue to have, a significant amount of indebtedness. As of December 31, 2013, our total debt was $888.1 million, including $1.5 million of premium, comprised of the aggregate principal amount due under our 7.75% Senior Notes due 2019 of $475.0 million, the aggregate principal amount due under our 7.75% Senior Notes due 2022 of $300.0 million and capital lease obligations in the aggregate amount of $111.6 million. There were no borrowings and $37.7 million of letters of credit outstanding under our $250.0 million revolving credit facility as of December 31, 2013. For the year ended December 31, 2013, we made cash interest payments totaling $62.6 million.

Our current and future indebtedness could have important consequences. For example, it could:

•impair our ability to make investments and obtain additional financing for working capital, capital expenditures, acquisitions or other general corporate purposes;

•limit our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make principal and interest payments on our indebtedness;

•make us more vulnerable to a downturn in our business, our industry or the economy in general as a substantial portion of our operating cash flow will be required to make principal and interest payments on our indebtedness, making it more difficult to react to changes in our business and in industry and market conditions;

•limit our ability to obtain additional financing that may be necessary to operate or expand our business;

•put us at a competitive disadvantage to competitors that have less debt; and

•increase our vulnerability to interest rate increases to the extent that we incur variable rate indebtedness.

If we are unable to generate sufficient cash flow or are otherwise unable to obtain the funds required to make principal and interest payments on our indebtedness, or if we otherwise fail to comply with the various covenants in instruments governing any existing or future indebtedness, we could be in default under the terms of such instruments. In the event of a default, the holders of our indebtedness could elect to declare all the funds borrowed under those instruments to be due and payable together with accrued and unpaid interest, secured lenders could foreclose on any of our assets securing their loans and we or one or more of our subsidiaries could be forced into bankruptcy or liquidation. If our indebtedness is accelerated, or we enter into bankruptcy, we may be unable to pay all of our indebtedness in full. Any of the foregoing consequences could restrict our ability to grow our business and cause the value of our common stock to decline.

Our Revolving Credit Facility and the indentures governing our 7.75% Senior Notes due 2019 and our 7.75% Senior Notes due 2022 impose restrictions on us that may affect our ability to successfully operate our business.

Our Revolving Credit Facility and the indentures governing our 7.75% Senior Notes due 2019 and our 7.75% Senior Notes due 2022 each impose limitations on our ability to take various actions, such as:

•limitations on the incurrence of additional indebtedness;

•restrictions on mergers, sales or transfers of assets without the lenders' consent; and

•limitations on dividends and distributions.

In addition, our Revolving Credit Facility requires us to maintain certain financial ratios and to satisfy certain financial conditions, some of which become more restrictive over time and may require us to reduce our debt or take some other action in order to comply with them. The failure to comply with any of these financial conditions, including the financial ratios or covenants, would cause a default under our Revolving Credit Facility. A default under any of our indebtedness, if not waived, could result in the acceleration of such indebtedness or other indebtedness, in which case the debt would become immediately due and payable. In addition, a default or acceleration of any of our indebtedness under our 7.75% Senior Notes due 2019, our 7.75% Senior Notes due 2022 or our Revolving Credit Facility could result in a default under or acceleration of other indebtedness with cross-default or cross-acceleration provisions. In the event of any acceleration of our indebtedness, we may not be able to pay our debt or borrow sufficient funds to refinance it, and any holders of secured indebtedness may seek to foreclose on the assets securing such indebtedness. Even if new financing is available, it may not be available on terms that are acceptable to us. These restrictions could also limit our ability to obtain future financings, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our Revolving Credit Facility or existing limitations on the incurrence of additional indebtedness, including in connection with acquisitions. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Revolving Credit Facility" for a discussion of our Revolving Credit Facility.

Our industry has experienced a high rate of employee turnover. Any difficulty we experience replacing or adding personnel could adversely affect our business.

We may not be able to find enough skilled labor to meet our needs, which could limit our growth. Our business activity historically decreases or increases with the prices of oil and natural gas. We may have problems finding enough skilled and unskilled laborers in the future if the demand for our services increases. If we are not able to increase our service rates sufficiently to compensate for wage rate increases, our operating results may be adversely affected.

Other factors may also inhibit our ability to find enough workers to meet our employment needs. Our services require skilled workers who can perform physically demanding work. As a result of our industry volatility and the demanding nature of the work, workers may choose to pursue employment in fields that offer a more desirable work environment at wage rates that are competitive with ours. We believe that our success is dependent upon our ability to continue to employ and retain skilled technical personnel. Our inability to employ or retain skilled technical personnel generally could have a material adverse effect on our operations.

Our success depends on key members of our management, the loss of any of whom could disrupt our business operations.

We depend to a large extent on the services of some of our executive officers. The loss of the services of Thomas M. “Roe” Patterson, our President and Chief Executive Officer, or other key personnel could disrupt our operations. Although we have entered into employment agreements with Mr. Patterson and our other executive officers that contain, among other provisions, non-compete agreements, we may not be able to enforce the non-compete provisions in the employment agreements.

Adverse weather conditions may affect our operations.

Our operations may be materially affected by severe weather conditions in areas where we operate. Severe weather, such as blizzards, extreme temperatures and hurricanes may cause evacuation of personnel, curtailment of services and suspension of operations, and loss of or damage to equipment and facilities. Damage from any adverse weather conditions could adversely affect our financial condition, results of operations and cash flows.

Weather conditions may also affect the price of crude oil and natural gas, and related demand for our services. Please read the risk factor above, “If oil and natural gas prices remain volatile, or if oil prices decline or natural gas prices remain low or decline further, the demand for our services could be adversely affected.”

We are subject to environmental, health and safety laws and regulations that may expose us to significant liabilities for penalties, damages or costs of remediation or compliance.

Our operations are subject to federal, regional, state and local laws and regulations relating to protection of natural resources and the environment, health and safety aspects of our operations and waste management, including the transportation and disposal of waste and other materials. These laws and regulations may impose numerous obligations on our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to mitigate or prevent releases of materials from our facilities, the imposition of substantial liabilities for pollution resulting from our operations and the application of specific health and safety criteria addressing worker protection. Failure to comply with these laws and regulations could result in investigations restrictions or orders suspending well operations, the assessment of administrative, civil and criminal penalties, the revocation of permits and the issuance of corrective action orders, any of which could have a material adverse effect on our business, results of operations and financial condition.

There is inherent risk of environmental costs and liabilities in our business as a result of our handling of petroleum hydrocarbons and oilfield and industrial wastes, air emissions and wastewater discharges related to our operations, and historical industry operations and waste disposal practices. Our fluid services segment includes disposal operations into injection wells that pose risks of environmental liability, including leakage from the wells to surface or subsurface soils, surface water or groundwater. Some environmental laws and regulations may impose strict liability, which means that in some situations, we could be exposed to liability as a result of our conduct that was without fault or lawful at the time it occurred or as a result of the conduct of, or conditions caused by, prior operators or other third parties. Clean-up costs and other damages arising as a result of environmental laws and costs associated with changes in environmental laws and regulations could be substantial and could have a material adverse effect on our financial condition and results of operations.

Laws protecting the environment generally have become more stringent over time and are expected to continue to do so, which could lead to material increases in costs for future environmental compliance and remediation. The modification or interpretation of existing laws or regulations, or the adoption of new laws or regulations, could curtail exploratory or developmental drilling for oil and natural gas and could limit well servicing opportunities. We may not be able to recover some or any of our costs of compliance with these laws and regulations from insurance.

Please read “Business — Environmental Regulation and Climate Change” for more information on the environmental laws and government regulations that are applicable to us.

Climate change legislation or regulations restricting or regulating emissions of greenhouse gases could result in increased operating costs and reduced demand for our field services.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases from industrial and energy sources contribute to increases of carbon dioxide levels in the earth’s atmosphere and oceans and contribute to global warming and other environmental effects, the EPA has adopted various regulations under the federal Clean Air Act addressing emissions of greenhouse gases that may affect the oil and gas industry. On August 16, 2012 the EPA published rules that include standards to reduce methane emissions associated with oil and gas production. Federal changes will affect state air permitting programs in states that administer the federal Clean Air Act under a delegation of authority, including states in which we have operations. In the recent Congress, numerous legislative measures were introduced that would have imposed restrictions or costs on greenhouse gas emissions, including from the oil and gas industry. It is uncertain whether similar measures will be introduced in, or passed by, the new Congress which convened in January 2014. In addition, the United States has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change. Additionally, certain U.S. states or regional coalitions of states have adopted measures regulating or limiting greenhouse gases from certain sources or have adopted policies seeking to reduce overall emissions of greenhouse gases. The adoption and implementation of any international treaty or of any federal or state legislation or regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to comply with such requirements and possibly require the reduction or limitation of emissions of greenhouse gases associated with our operations and other sources within the industrial or energy sectors. Such legislation or regulations could adversely affect demand for the production of oil and natural gas and thus reduce demand for the services we provide to oil and natural gas producers as well as increase our operating costs by requiring additional costs to operate and maintain equipment and facilities, install emissions controls, acquire allowances or pay taxes and fees relating to emissions, which could adversely affect our results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases may produce changes in climate or weather, such as increased frequency and severity of storms, floods and other climatic events, which if any such effects were to occur, could have adverse physical effects on our operations, physical assets and field services to exploration and production operators.

Federal and state legislative and regulatory initiatives related to hydraulic fracturing could result in operating restrictions or delays in the completion of oil and natural gas wells that may reduce demand for our well servicing activities and could adversely affect our financial position, results of operations and cash flows.

We provide hydraulic fracturing and fluid handling services to our customers. Hydraulic fracturing is a commonly used process that involves injection of water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The federal Energy Policy Act of 2005 amended the Underground Injection Control ("UIC") provisions of the federal Safe Drinking Water Act ("SDWA") to exclude certain hydraulic fracturing practices from the definition of "underground injection." The EPA has asserted regulatory authority over certain hydraulic fracturing activities involving diesel fuel and published proposed guidance relating to such practices in May 2012. In addition, repeal of the SDWA exclusion of hydraulic fracturing has been advocated by certain advocacy organizations and others in the public. Congress has considered bills to repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate new regulations and permitting requirements for hydraulic fracturing, and would require the disclosure of the chemical constituents of hydraulic fracturing fluids to a regulatory agency, which would make the information public via the internet. At the state level, several states in which we operate have adopted regulations requiring the disclosure of certain information regarding hydraulic fracturing fluids. Scrutiny of hydraulic fracturing activities continues in other ways, as the EPA commenced a study of the potential environmental impacts of hydraulic fracturing and issued an update on December 21, 2012, with the final results expected in 2014. As the result of a separate study in Pavillion, Wyoming, the EPA issued a report in December 2011 that suggests a link between hydraulic fracturing and groundwater contamination in the area. An independent peer-reviewed process has been instituted to review the findings. The U.S. Department of the Interior has also announced that it will consider regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid constituents. On April 13, 2012, the Department of Interior, the Department of Energy and the EPA issued a memorandum outlining a multi-agency collaboration on unconventional oil and gas research in response to the White House "Blueprint for a Secure Energy Future" and the recommendations of the Secretary of Energy Advisory Board Subcommittee on Natural Gas. In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, that would require, with some exceptions, disclosure of constituents of hydraulic fracturing fluids, or that would impose higher taxes, fees or royalties on natural gas production. Moreover, public debate over hydraulic fracturing and shale gas production has been increasing, and has resulted in delays of well permits in some areas.

In 2010, a committee of the U.S. House of Representatives undertook investigations into hydraulic fracturing practices involving the use of diesel fuel in hydraulic fracturing fluids, including requesting information from various field services companies including us. We responded to that request and have received no further communication from the committee with regard to that investigation. However, on January 31, 2011, Representative Henry Waxman and other members of Congress wrote to the EPA asserting that various companies, including us, had engaged in hydraulic fracturing operations requiring a permit without obtaining such a permit. We have no knowledge as to whether or how the EPA will respond to that letter.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, incurred by our customers or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations or ordinances restricting or increasing the costs of hydraulic fracturing could potentially increase our costs of operations and cause a decrease in the completion of new oil and natural gas wells and an associated decrease in demand for our well servicing activities, any or all of which could adversely affect our financial position, results of operations and cash flows.

Potential listing of species as “endangered” under the federal Endangered Species Act could result in increased costs and new operating restrictions or delays on our oil and natural gas exploration and production customers, which could adversely reduce the amount of contract drilling services that we provide to such customers.

The federal Endangered Species Act, referred to as the “ESA,” and analogous state laws regulate a variety of activities, including oil and gas development, which could have an adverse effect on species listed as threatened or endangered under the ESA or their habitats. The designation of previously unidentified endangered or threatened species could cause oil and natural gas exploration and production operators to incur additional costs or become subject to operating delays, restrictions or bans in affected areas, which impacts could adversely reduce the amount of drilling activities in affected areas, including support services that we provide to such operators under our contract drilling services segment. Numerous species have been listed or proposed for protected status in areas in which we provide or could in the future provide field services. For instance, the Sand Dune Lizard, referred to as “Lizard,” a small lizard found in southeastern New Mexico and west Texas, an area where we provide a significant level of contract drilling services to oil and natural gas exploration and production operators, was proposed for listing as an endangered species under the ESA in December 2010 by the U.S. Fish & Wildlife Service, also referred to as the “FWS.” In December 2013, FWS initiated a special rule that would exempt from regulation under the ESA activities harmful to the prairie-chicken if incidental to carrying out the state-developed range-wide lesser prairie-chicken conservation plan, in the event the species warrants listing as “threatened” under the ESA. In February 2014, FWS announced its intent to prepare a draft Environmental Impact Statement to evaluate the proposed

Stakeholder Conservation Strategy for the lesser prairie-chicken developed by the American Habitat Center. The sage grouse and certain wildflower species, among others, are also species that have been or are being considered for protected status under the ESA and whose range can coincide with oil and natural gas production activities. The presence of protected species in areas where operators whom we provide contract drilling services conduct exploration and production operations could impair such operators' ability to timely complete well drilling and development and, consequently, adversely affect the amount of contract drilling or other field services that we provided to such operators, which reduction of services could have a significant adverse effect on our results of operations and financial position.

One of our directors may have a conflict of interest because he is also currently a managing partner of a private equity firm that makes investments in the energy sector. The resolution of any conflict of interest may not be in our or our stockholders' best interests.

Steven A. Webster, the Chairman of our Board of Directors, is the Co-Managing Partner of Avista Capital Holdings, L.P., a private equity firm that makes investments in the energy sector. This relationship may create a conflict of interest because of his responsibilities to Avista and its owners. His duties as a partner in, or director or officer of, Avista or its affiliates may conflict with his duties as a director of our company regarding corporate opportunities and other matters. The resolution of any such conflict may not always be in our or our stockholders' best interest.

Risks Relating to Our Relationship with Credit Suisse

Affiliates of Credit Suisse will have a substantial influence on the outcome of stockholder voting and may exercise this voting power in a manner that may not be in the best interest of our other stockholders.

As of February 24, 2014, DLJ Merchant Banking Partners III, L.P. and affiliated funds ("DLJ Merchant Banking"), which are managed by affiliates of Credit Suisse AG, a Swiss Bank, beneficially owned approximately 29% of our outstanding common stock. Accordingly, Credit Suisse is in a position to have a substantial influence on the outcome of matters requiring a stockholder vote, including the election of directors, adoption of amendments to our certificate of incorporation or bylaws or approval of transactions involving a change of control. The interests of Credit Suisse may differ from those of our other stockholders, and Credit Suisse may vote its common stock in a manner that may adversely affect our other stockholders.

Risks Relating to Ownership of Our Common Stock

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

•a classified board of directors, so that only approximately one third of our directors are elected each year;

•limitations on the removal of directors;

•the prohibition of stockholder action by written consent;

•limitations on the ability of our stockholders to call special meetings; and

•advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any “interested stockholder,” meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that the board of directors deems relevant. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

ITEM 1B.UNRESOLVED STAFF COMMENTS

None.

ITEM 3.LEGAL PROCEEDINGS

From time to time, Basic is a party to litigation or other legal proceedings that Basic considers to be a part of the ordinary course of business. Basic is not currently involved in any legal proceedings that it considers probable or reasonably possible, individually or in the aggregate, to result in a material adverse effect on its financial condition, results of operations or liquidity. The information regarding litigation and environmental matters described in Note 7 of the notes to our audited consolidated financial statements included in this Annual Report on Form 10-K is incorporated herein by reference.

ITEM 4.MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5.MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Price for Registrant's Common Equity

Our common stock is traded on the New York Stock Exchange under the symbol "BAS." The table below presents the high and low daily closing sales prices of the common stock, as reported by the New York Stock Exchange, for each of the quarters in the years ended December 31, 2012 and 2013, respectively:

	High	Low
2012:		
First Quarter	$ 21.86	$ 16.18
Second Quarter	$ 17.99	$ 8.71
Third Quarter	$ 13.67	$ 9.05
Fourth Quarter	$ 12.39	$ 8.96
2013:		
First Quarter	$ 16.00	$ 11.63
Second Quarter	$ 14.51	$ 11.85
Third Quarter	$ 14.65	$ 11.30
Fourth Quarter	$ 16.80	$ 12.06

As February 24, 2014, we had 42,506,046 shares of common stock outstanding held by approximately 268 record holders.

We have not declared or paid any cash dividends on our common stock, and we do not currently anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any future determination relating to our dividend policy will be at the discretion of our board of directors and will depend on our results of operations, financial condition, capital requirements and other factors deemed relevant by our board.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information regarding options or warrants authorized for issuance under our equity compensation plans as of December 31, 2013:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders	530,000	$ 18.15	2,851,280
Equity compensation plans not approved by security holders	—	—	—
Total	530,000	$ 18.15	2,851,280

(1) Consists of the Basic Energy Services, Inc. Fifth Amended and Restated 2003 Incentive Plan (as amended effective May 22, 2013).

Issuer Purchases of Equity Securities

The following table provides information relating to our repurchase of shares of common stock during the three months ended December 31, 2013 (dollars in thousands, except average price paid per share):

Issuer Purchases of Equity Securities				
Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program (1)	Approximate Dollar Value of Shares that May Yet be Purchased Under the Program (1)
October 1 — October 31 (2)	2,544	$ 12.96	—	$ 23,089
November 1 — November 30 (2)	—	$ —	—	$ 23,089
December 1 — December 31 (2)	704	$ 15.03	—	$ 23,089
Total	3,248	$ 13.41	—	$ 23,089

(1) On May 24, 2012, we announced that our Board of Directors had reauthorized the repurchase of up to approximately $35.2 million of shares of our common stock from time to time in open market or private transactions, at our discretion, as a continuation of our prior $50.0 million stock repurchase program announced in 2008 (of which $14.8 million has been previously purchased). The stock repurchase program may be suspended or discontinued at any time.

(2) These amounts include shares that were repurchased from various employees to provide such employees the cash amounts necessary to pay certain tax liabilities associated with the vesting of restricted shares owned by them. The shares were repurchased on various dates based on the closing price per share on the date of repurchase.

Performance Graph

The following is a line graph comparing cumulative, total shareholder return for the five years ended December 31, 2013 with (i) a general market index (the Russell 2000 Index) and (ii) a group of peers selected by the Company in the same line of business or industry as the Company. The peer group is comprised of the following companies: Key Energy Services, Inc., Nabors Industries, Ltd. and Pioneer Energy Services.

The graph assumes investments of $100 on December 31, 2008 at the closing sale price, and the reinvestment of all dividends, if any.

The graph shall not be deemed incorporated by reference by any general statement incorporating by reference this report into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that the Company specifically incorporates this information by reference, and shall not otherwise be deemed filed under such Acts.

Comparison of Five Year Cumulative Total Return

Value of $100 Invested at December 31, 2008, December 31, 2009, December 31, 2010,

December 30, 2011, December 30, 2012 and December 31, 2013

T

	Basic Energy Services		Russell 2000 Index		Peer Group	
December 31, 2008	$	100.00	$	100.00	$	100.00
December 31, 2009	$	68.25	$	125.22	$	181.15
December 31, 2010	$	126.38	$	156.90	$	202.02
December 30, 2011	$	151.07	$	148.35	$	169.39
December 31, 2012	$	87.50	$	170.06	$	122.10
December 31, 2013	$	121.01	$	232.98	$	143.29

The foregoing graph is based on historical data and is not necessarily indicative of future performance. This graph shall not be deemed to be “soliciting material” or to be “filed” with the SEC or subject to the Regulations 14A or 14C under the Securities Exchange Act of 1934, as amended, or to the liabilities of Section 18 under such Act.

ITEM 6.SELECTED FINANCIAL DATA

The following table sets forth our selected historical financial information for the periods shown. The following information should be read in conjunction with Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and our financial statements included elsewhere in this report. The amounts for each historical annual period presented below were derived from our audited financial statements.

	Year Ended December 31,				
	2013	2012 (a)	2011 (a)	2010 (a)	2009 (a)
	(Dollars in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Completion and remedial services	$ 501,137	$ 586,070	$ 537,134	$ 261,436	$ 134,818
Fluid services	343,863	352,246	332,010	241,164	214,822
Well servicing	363,386	376,268	333,057	204,872	160,614
Contract drilling	54,518	60,300	41,054	20,767	16,373
Total revenues	1,262,904	1,374,884	1,243,255	728,239	526,627
Expenses:					
Completion and remedial services	327,540	357,960	297,276	156,573	95,287
Fluid services	239,154	236,588	211,959	178,152	159,079
Well servicing	265,058	268,219	228,723	156,885	121,618
Contract drilling	36,336	39,817	28,154	15,250	13,604
General and administrative (b)	171,439	183,274	144,485	108,831	104,964
Depreciation and amortization	209,747	187,083	154,341	135,001	132,520
Loss on disposal of assets	2,873	3,334	447	2,856	2,650
Goodwill impairment	-	-	-	-	204,014
Total expenses	1,252,147	1,276,275	1,065,385	753,548	833,736
Operating income (loss)	10,757	98,609	177,870	(25,309)	(307,109)
Net interest expense	(67,154)	(62,355)	(52,299)	(46,368)	(32,386)
Loss on early extinguishment of debt	-	(7,942)	(49,366)	-	(3,481)
Bargain Purchase gain	-	910	-	1,772	-
Other income	743	627	525	499	1,198
Income (loss) from continuing operations before income taxes	(55,654)	29,849	76,730	(69,406)	(341,778)
Income tax (expense) benefit	19,725	(10,263)	(30,894)	25,174	87,711
Income (loss) from continuing operations	(35,929)	19,586	45,836	(44,232)	(254,067)
Net income (loss)	(35,929)	19,586	45,836	(44,232)	(254,067)
Net income (loss) available to common stockholders	$ (35,929)	$ 19,586	$ 45,836	(44,232)	$ (254,067)
Basic earnings (loss) per share of common stock:	$ (0.89)	$ 0.48	$ 1.14	$ (1.11)	$ (6.40)
	$ (0.89)	$ 0.47	$ 1.10	$ (1.11)	$ (6.40)

Diluted earnings (loss) per share of common stock:					
Other Financial Data:					
Cash flows from operating activities	$ 165,588	$ 303,681	$ 279,455	$ 49,383	$ 89,205
Cash flows from investing activities	(139,686)	(250,762)	(419,967)	(97,879)	(62,864)
Cash flows from financing activities	(48,935)	3,188	171,052	(28,943)	(12,119)
Capital expenditures:					
Acquisitions, net of cash acquired	21,467	84,939	218,347	50,278	7,816
Property and equipment	136,950	171,440	221,839	63,579	43,367

(a) As corrected for immaterial errors as discussed in the footnotes to our 2013 financial statements.
(b) Includes approximately $11,830, $12,855, $9,487, $6,027 and $5,214 of non-cash stock compensation expense for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively.

	As of December 31,				
	2013	2012 (a)	2011 (a)	2010 (a)	2009 (a)
	(Dollars in thousands)				
Balance Sheet Data:					
Cash and cash equivalents	$ 111,532	$ 134,565	$ 78,458	$ 47,918	125,357
Property and equipment, net	928,037	943,766	856,412	625,702	666,642
Total assets	1,543,339	1,599,006	1,462,352	1,031,342	1,041,451
Long-term debt	846,691	844,906	748,976	474,628	475,845
Stockholders' equity	345,287	372,410	357,668	299,683	338,217

(a) As corrected for immaterial errors as discussed in the footnotes to our 2013 financial statements.

ITEM 7.MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Overview

We provide a wide range of well site services to oil and natural gas drilling and producing companies, including completion and remedial services, fluid services, well servicing and contract drilling services. Our results of operations reflect the impact of our acquisition strategy as a leading consolidator in the domestic land-based well services industry. Our acquisitions have increased our breadth of service offerings at the well site and expanded our market presence. In implementing this strategy, we have purchased businesses and assets in 11 separate acquisitions from January 1, 2011 to December 31, 2013 for total consideration of $322.8 million. Our hydraulic horsepower capacity for pumping services increased from 142,000 at January 1, 2011 to 297,000 at December 31, 2013. Our weighted average number of fluid service trucks increased from 820 in the first quarter of 2011 to 986 in the fourth quarter of 2013. Our weighted average number of well servicing rigs increased from 412 in the first quarter of 2011 to 425 in the fourth quarter of 2013. Our weighted average number of drilling rigs increased from six in the first quarter of 2011 to 12 in the fourth quarter of 2013. These acquisitions make changes in revenues, expenses and income not directly comparable between periods.

Our operating revenues from each of our segments, and their relative percentages of our total revenues, consisted of the following (dollars in millions):

	Year Ended December 31,					
	2013		2012		2011	
Revenues:						
Completion and remedial services	$ 501.1	40%	$ 586.1	43%	$ 537.1	43%
Fluid services	343.9	27%	352.2	26%	332.0	27%
Well servicing	363.4	29%	376.3	27%	333.1	27%
Contract drilling	54.5	4%	60.3	4%	41.1	3%
Total revenues	$ 1,262.9	100%	$ 1,374.9	100%	$ 1,243.3	100%

Our core businesses depend on our customers' willingness to make expenditures to produce, develop and explore for oil and natural gas in the United States. Industry conditions are influenced by numerous factors, such as the supply of and demand for oil and natural gas, domestic and worldwide economic conditions, political instability in oil producing countries and merger and divestiture activity among oil and natural gas producers. The volatility of the oil and natural gas industry, and the consequent impact on exploration and production activity, could adversely impact the level of drilling and workover activity by some of our customers. This volatility also affects the demand for our services and the price of our services. In addition, the discovery rate of new oil and natural gas reserves in our market areas also may have an impact on our business, even in an environment of stronger oil and natural gas prices. For a more comprehensive discussion of our industry trends, see "General Industry Overview" included in Items 1 and 2, Business and Properties, of this Annual Report on Form 10-K.

We derive a majority of our revenues from services supporting production from existing oil and natural gas operations. Demand for these production-related services, including well servicing and fluid services, tends to remain relatively stable, even in moderate oil and natural gas price environments, as ongoing maintenance spending is required to sustain production. As oil and natural gas prices reach higher levels, demand for all of our services generally increases as our customers engage in more well servicing activities relating to existing wells to maintain or increase oil and natural gas production from those wells. Because our services are required to support drilling and workover activities, our revenues will vary based on changes in capital spending by our customers as oil and natural gas prices increase or decrease.

During 2010, oil prices remained relatively stable following the increase in prices experienced during 2009. Oil prices increased during the first half of 2011 primarily due to political and economic instability in several oil producing countries and remained relatively stable during the last months of 2011 and throughout 2012 and 2013. This trend in oil prices has caused utilization and pricing for our services to stabilize in our oil-based operating areas, while utilization and pricing for our services in our natural gas-based operating areas remained depressed throughout 2013 due to low natural gas prices. This extended low level of natural gas pricing has caused overcapacity and pricing pressure on all service lines, as the majority of the equipment in the North American market has been focused in oil-dominated areas.

Our revenues generally declined in 2013, primarily due to significant competition and rate pressure across all segments and geographies. This decline was most notable in our completion and remedial services segment. These declines were somewhat offset by increased fluid services activity, particularly with the addition of 10 salt water disposal facilities and 48 fluid service trucks during the year. We anticipate our customer base to begin their 2014 capital programs early in the year, and expect higher activity levels in 2014 accordingly. We also continue to anticipate high levels of competitive service capacity and wage competition through 2014. As the year progresses, we expect the higher levels of activity and wage pressure to create an environment in which pricing may increase. In some of our markets, overall service capacity may come into balance with activity levels to the extent where pricing may more than offset increases in wages and direct cost, allowing for modest incremental margin improvement.

We will continue to evaluate opportunities to expand our business through selective acquisitions and internal growth initiatives. Our capital investment decisions are determined by an analysis of the projected return on capital employed of each of those alternatives, which is substantially driven by the cost to acquire existing assets from a third party, the capital required to build new equipment and the point in the oil and natural gas commodity price cycle. Based on these factors, we make capital investment decisions that we believe will support our long-term growth strategy. While we believe our costs of integration for prior acquisitions have been reflected in our historical results of operations, integration of acquisitions may result in unforeseen operational difficulties or require a disproportionate amount of our management's attention.

We believe that the most important performance measures for our business segments are as follows:

•Completion and Remedial Services — segment profits as a percent of revenues;

•Fluid Services — trucking hours, revenue per truck, segment profits per truck and segment profits as a percent of revenues;

•Well Servicing — rig hours, rig utilization rate, revenue per rig hour, profits per rig hour and segment profits as a percent of revenues; and

•Contract Drilling — rig operating days, revenue per drilling day, profits per drilling day and segment profits as a percent of revenues.

Segment profits are computed as segment operating revenues less direct operating costs. These measurements provide important information to us about the activity and profitability of our lines of business. For a detailed analysis of these indicators for our company, see "Segment Overview" below.

Recent Strategic Acquisitions and Expansions

During the period from 2011 through 2013, we grew through acquisitions and capital expenditures. During 2011, we completed four acquisitions, of which the Maverick Companies was considered significant. During 2012, we completed four acquisitions, none of which were considered significant. During 2013, we completed three acquisitions that complemented our existing business segments, none of which were considered significant.

We discuss the aggregate purchase prices and related financing issues below in "Liquidity and Capital Resources" and present the pro forma effects of the acquisition of the Maverick Companies in Note 3 of the notes to our historical consolidated financial statements included in this report.

Selected 2011 Acquisitions

During 2011, we made four acquisitions that complemented our existing business segments. These included, among others:

The Maverick Companies

On July 8, 2011, we acquired all the equity interests of Maverick Stimulation Company, LLC, Maverick Coil Tubing Services, LLC, Maverick Thru-Tubing Services, LLC, Maverick Solutions, LLC, The Maverick Companies, LLC, MCM Holdings, LLC, and MSM Leasing LLC (collectively, the "Maverick Companies") for total consideration of $186.3 million in cash. This acquisition has been included in our completion and remedial services segment.

Selected 2012 Acquisitions

During 2012, we made four acquisitions that complemented our existing business segments. These included, among others:

Surface Stac, Inc.

On May 15, 2012, we acquired substantially all of the assets of Surface Stac, Inc for total consideration of $23.2 million in cash. This acquisition has been included in our completion and remedial services segment.

Salt Water Disposal of North Dakota LLC

On December 19, 2012, we acquired substantially all of the assets of Salt Water Disposal of North Dakota LLC for total consideration of $43.2 million in cash. This acquisition has been included in our fluid services segment.

Selected 2013 Acquisitions

During 2013, we made three acquisitions that complemented our existing business segments. These included, among others:

Atlas Environmental Consulting, Inc. and Atlas Oilfield Construction Company, LLC

On February 16, 2013, we acquired all of the assets of Atlas Environmental Consulting, Inc. and Atlas Oilfield Construction Company, LLC for total cash consideration of $13.0 million. This acquisition has been included in our fluid services segment.

Segment Overview

Completion and Remedial Services

In 2013, our completion and remedial services segment represented 40% of our revenues. Revenues from our completion and remedial services segment are generally derived from a variety of services designed to stimulate oil and natural gas production or place cement slurry within the wellbores. Our completion and remedial services segment includes pumping services, rental and fishing tool operations, coiled tubing services, nitrogen services, cased-hole wireline services, snubbing and underbalanced drilling.

Our pumping services concentrate on providing single truck, lower-horsepower cementing, acidizing and fracturing services in selected markets. Our total hydraulic horsepower capacity for our pumping services was approximately 297,000 horsepower at December 31, 2013, compared to 291,000 horsepower and 271,000 horsepower at December 31, 2012 and December 31, 2011, respectively.

Our rental and fishing tool business operates 23 rental and fishing tool stores in selected markets as of December 31, 2013.

Our snubbing services operate 37 units throughout our geographic footprint as of December 31, 2013. We entered the snubbing business in 2009 with the acquisition of Team Snubbing Services, which operated in Arkansas. We further expanded our snubbing business in 2010 through the acquisition of Platinum Pressure Services, Inc., which operated in Texas, Oklahoma, Arkansas, Louisiana and Pennsylvania.

We have operations in the wireline, coiled tubing services, nitrogen services, water treatment and the underbalanced drilling services businesses. For a description of our wireline, underbalanced drilling services, coiled tubing services, nitrogen services, water treatment, and snubbing operations, please read “Overview of Our Segments and Services — Completion and Remedial Services Segment” included in Items 1 and 2, Business and Properties, of this Annual Report on Form 10-K.

In this segment, we generally derive our revenues on a project-by-project basis in a competitive bidding process. Our bids are generally based on the amount and type of equipment and personnel required, with the materials consumed billed separately. During periods of decreased spending by oil and gas companies, we may be required to discount our rates to remain competitive, which would cause lower segment profits.

The following is an analysis of our completion and remedial services segment for each of the quarters and years in the years ended December 31, 2011, 2012 and 2013 (dollars in thousands):

Completion & Remedial	Revenues		Segment Profits %
2011:			
First Quarter	$	97,507	44%
Second Quarter	$	121,807	44%
Third Quarter	$	157,121	46%
Fourth Quarter	$	160,699	45%
Full Year	$	537,134	45%
2012:			
First Quarter	$	164,420	41%

Second Quarter	$	156,560	41%
Third Quarter	$	143,348	39%
Fourth Quarter	$	121,742	34%
Full Year	$	586,070	39%
2013:			
First Quarter	$	118,361	33%
Second Quarter	$	132,216	35%
Third Quarter	$	127,119	35%
Fourth Quarter	$	123,441	35%
Full Year	$	501,137	35%

We gauge the performance of our completion and remedial services segment based on the segment's operating revenues and segment profits as a percent of revenues.

Fluid Services

In 2013, our fluid services segment represented 27% of our revenues. Revenues in our fluid services segment are earned from the sale, transportation, storage and disposal of fluids used in the drilling, production and maintenance of oil and natural gas wells. Revenues also include water treatment, well site construction and maintenance services. The fluid services segment has a base level of business consisting of transporting and disposing of salt water produced as a by-product of the production of oil and natural gas. These services are necessary for our customers and generally have a stable demand but typically produce lower relative segment profits than other parts of our fluid services segment. Fluid services for completion and workover projects typically require fresh or brine water for making drilling mud, circulating fluids or frac fluids used during a job, and all of these fluids require storage tanks and hauling and disposal. Because we can provide a full complement of fluid sales, trucking, storage and disposal required on most drilling and workover projects, the add-on services associated with drilling and workover activity enable us to generate higher segment profits. The higher segment profits are due to the relatively small incremental labor costs associated with providing these services in addition to our base fluid services operations. Revenues from our well site construction services are derived primarily from preparing and maintaining access roads and well locations, installing small diameter gathering lines and pipelines, constructing foundations to support drilling rigs and providing maintenance services for oil and natural gas facilities. Revenue from water treatment services results from the treatment and reselling of produced water and flowback to customers for the purposes of reusing as frac water. We typically price fluid services by the job, by the hour or by the quantities sold, disposed of or hauled.

The following is an analysis of our fluid services segment for each of the quarters and years in the years ended December 31, 2011, 2012 and 2013 (dollars in thousands):

Fluid Services	Weighted Average Number of Fluid Service Trucks	Truck Hours	Revenue Per Fluid Service Truck	Segment Profits Per Fluid Service Truck	Segment Profits %
2011:					
First Quarter	820	494,700	$ 88	$ 29	33%
Second Quarter	837	525,700	$ 97	$ 36	37%
Third Quarter	869	563,900	$ 101	$ 38	37%
Fourth Quarter	875	570,800	$ 104	$ 38	37%
Full Year	850	2,155,100	$ 391	$ 141	36%
2012:					
First Quarter	900	580,700	$ 106	$ 36	34%
Second Quarter	918	552,400	$ 99	$ 35	36%
Third Quarter	931	551,600	$ 91	$ 29	32%
Fourth Quarter	954	555,200	$ 86	$ 25	29%
Full Year	926	2,239,900	$ 380	$ 125	33%
2013:					
First Quarter	972	555,600	$ 88	$ 27	31%
Second Quarter	972	568,500	$ 88	$ 27	31%
Third Quarter	970	578,900	$ 89	$ 27	31%
Fourth Quarter	986	579,400	$ 89	$ 26	29%
Full Year	975	2,282,400	$ 353	$ 107	30%

We gauge activity levels in our fluid services segment based on trucking hours, revenue per fluid service truck, segment profits per fluid service truck and segment profits as a percent of revenues.

Well Servicing

In 2013, our well servicing segment represented 29% of our revenues. Revenue in our well servicing segment is derived from maintenance, workover, completion and plugging and abandonment services, as well as rig manufacturing operations. We provide maintenance-related services as part of the normal, periodic upkeep of producing oil and natural gas wells. Maintenance-related services represent a relatively consistent component of our business. Workover and completion services generate more revenue per hour than maintenance work due to the use of auxiliary equipment, but demand for workover and completion services fluctuates more with the overall activity level in the industry.

We typically charge our well servicing rig customers for services on an hourly basis at rates that are determined by the type of service and equipment required, market conditions in the region in which the rig operates, the ancillary equipment provided on the rig and the necessary personnel. We measure the activity level of our well servicing rigs on a weekly basis by calculating a rig utilization rate based on a 55-hour work week per rig.

We acquired our rig manufacturing business in May 2010. We manufacture workover rigs for internal purposes as well as to sell to outside companies. Our rig manufacturing operation also performs large scale refurbishments and maintenance services to used workover rigs.

The following is an analysis of our well servicing segment for each of the quarters and years in the years ended December 31, 2011, 2012 and 2013. The revenues do not include revenues associated with rig manufacturing operations:

Well Service	Weighted Average Number of Rigs	Rig Hours	Rig Utilization Rate	Revenue Per Rig Hour		Profits Per Rig Hour		Segment Profits %
2011:								
First Quarter	412	184,700	62.7%	$	356	$	105	30%
Second Quarter	412	205,700	69.8%	$	376	$	122	32%
Third Quarter	415	222,100	74.8%	$	386	$	117	31%
Fourth Quarter	417	217,100	72.8%	$	398	$	132	33%
Full Year	414	829,600	70.1%	$	380	$	119	31%
2012:								
First Quarter	423	231,300	76.5%	$	393	$	117	30%
Second Quarter	431	232,500	75.4%	$	399	$	111	27%
Third Quarter	431	226,400	73.5%	$	402	$	124	30%
Fourth Quarter	429	203,000	66.2%	$	393	$	108	27%
YTD 2012	429	893,200	72.9%	$	397	$	115	29%
2013:								
First Quarter	425	210,800	69.4%	$	399	$	117	30%
Second Quarter	425	223,900	73.7%	$	408	$	111	27%
Third Quarter	425	227,100	74.7%	$	404	$	124	30%
Fourth Quarter	425	199,400	65.6%	$	404	$	113	27%
YTD 2012	425	861,200	70.9%	$	404	$	114	27%

We gauge activity levels in our well servicing rig operations based on rig hours, rig utilization rate, revenue per rig hour, profits per rig hour and segment profits as a percent of revenues.

Contract Drilling

In 2013, our contract drilling segment represented 4% of our revenues. Revenues from our contract drilling segment are derived primarily from the drilling of new wells.

Within this segment, we typically charge our drilling rig customers at a daywork daily rate, or footage at an established rate per number of feet drilled. Depending on the type of job, we may also charge by the project. We measure the activity level of our drilling rigs on a weekly basis by calculating a rig utilization rate based on a seven-day work week per rig. We acquired six used drilling rigs during 2011 from several different companies. We acquired two drilling rigs during the first quarter of 2012, which increased our total number of drilling rigs to 12.

The following is an analysis of our contract drilling segment for each of the quarters and years in the years ended December 31, 2011, 2012 and 2013 (dollars in thousands):

Contract Drilling	Weighted Average Number of Rigs	Rig Operating Days	Revenue Per Day		Profits (Loss) Per Day		Segment Profits %
2011:							
First Quarter	6	522	$	13,500	$	4,900	36%
Second Quarter	10	714	$	13,700	$	3,300	24%
Third Quarter	10	802	$	14,600	$	4,700	32%
Fourth Quarter	10	851	$	14,700	$	5,000	34%
Full Year	9	2,889	$	14,200	$	4,500	31%
2012:							
First Quarter	12	967	$	15,800	$	5,200	33%
Second Quarter	12	1,007	$	15,500	$	5,800	37%
Third Quarter	12	957	$	15,800	$	5,300	34%
Fourth Quarter	12	892	$	16,000	$	5,100	32%
Full Year	12	3,823	$	15,800	$	5,300	34%
2013:							
First Quarter	12	850	$	16,500	$	5,700	25%
Second Quarter	12	846	$	16,500	$	5,000	30%
Third Quarter	12	833	$	16,500	$	5,500	34%
Fourth Quarter	12	781	$	16,400	$	5,800	35%
Full Year	12	3,310	$	16,500	$	5,500	33%

We gauge activity levels in our drilling operations based on rig operating days, revenue per drilling day, profits per drilling day and segment profits as a percent of revenues.

Operating Cost Overview

Our operating costs are comprised primarily of labor costs, including workers' compensation and health insurance, repair and maintenance, fuel and insurance. A majority of our employees are paid on an hourly basis. We also incur costs to employ personnel to sell and supervise our services and perform maintenance on our fleet. These costs are not directly tied to our level of business activity. Compensation for our administrative personnel in local operating yards and in our corporate office is accounted for as general and administrative expenses. Repair and maintenance is performed by our crews, company maintenance personnel and outside service providers. Insurance is generally a fixed cost regardless of utilization and relates to the number of rigs, trucks and other equipment in our fleet, employee payroll and our safety record.

Critical Accounting Policies and Estimates

Our consolidated financial statements are impacted by the accounting policies used and the estimates and assumptions made by management during their preparation. A complete summary of these policies is included in Note 2 of the notes to our historical consolidated financial statements. The following is a discussion of our critical accounting policies and estimates.

Critical Accounting Policies

We have identified below accounting policies that are of particular importance in the presentation of our financial position, results of operations and cash flows and which require the application of significant judgment by management.

Property and Equipment. Property and equipment are stated at cost, or at estimated fair value at acquisition date if acquired in a business combination. Expenditures for repairs and maintenance are charged to expense as incurred. We also review the capitalization of refurbishment of workover rigs as described in Note 2 of the notes to our historical consolidated financial statements.

Impairments. We review our assets for impairment at a minimum annually, or whenever, in management's judgment, events or changes in circumstances indicate that the carrying amount of a long-lived asset may not be recovered over its remaining service life. Impairment is indicated when the sum of the estimated future cash flows, on an undiscounted basis, is less than the asset's carrying amount. When impairment is identified and fair value is less than carrying value, an impairment charge is recorded to income based on an estimate of future cash flows on a discounted basis.

Self-Insured Risk Accruals. We are self-insured up to retention limits with regard to workers' compensation, general liability claims, and medical and dental coverage of our employees. We generally maintain no physical property damage coverage on our workover rig fleet, with the exception of certain of our 24-hour workover rigs and newly manufactured rigs. We have deductibles per occurrence for workers' compensation, general liability claims, and medical and dental coverage of $5 million, $1 million, and $350,000, respectively. We have lower deductibles per occurrence for automobile liability. We maintain accruals in our consolidated balance sheets related to self-insurance retentions by using third-party actuarial data and historical claims history.

Revenue Recognition. We recognize revenues when the services are performed, collection of the relevant receivables is probable, persuasive evidence of the arrangement exists and the price is fixed and determinable. Rig manufacturing revenue is recognized by individual rig based on the completed contract method.

Income Taxes. We recognize deferred tax assets and liabilities 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 statutory tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in the period that includes the statutory enactment date. A valuation allowance for deferred tax assets is recognized when it is more likely than not that the benefit of deferred tax assets will not be realized.

Critical Accounting Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the balance sheet date and the amounts of revenues and expenses recognized during the reporting period. We analyze our estimates based on historical experience and various other assumptions that we believe to be reasonable under the circumstances. However, actual results could differ from such estimates. The following is a discussion of our critical accounting estimates.

Depreciation and Amortization. In order to depreciate and amortize our property and equipment and our intangible assets with finite lives, we estimate the useful lives and salvage values of these items. Our estimates may be affected by such factors as changing market conditions, technological advances in the industry or changes in regulations governing the industry.

Impairment of Property and Equipment. Our analysis for potential impairment of property and equipment requires us to estimate undiscounted future cash flows. Actual impairment charges are recorded using an estimate of discounted future cash flows. The determination of future cash flows requires us to estimate rates and utilization in future periods and such estimates can change based on market conditions, technological advances in industry or changes in regulations governing the industry. We analyze the potential impairment of property and equipment annually as of December 31 or on an interim basis if events or circumstances indicate that the fair value of the assets have decreased below the carrying value.

Impairment of Goodwill. Goodwill is not amortized. We assess impairment of goodwill 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. A qualitative assessment of whether it is more likely than not that the fair value of a reporting unit is less that its carrying value is allowed but not required. If it is more likely than not that the fair value of the reporting unit is less than its carrying amount, then the two-step impairment test is performed. In the two-step test, first, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the fair value of the reporting unit's goodwill is determined by allocating the unit's fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination. The amount of impairment for goodwill is measured as the excess of its carrying value over its fair value. It is possible, depending upon a number of factors that are not determinable at this time or within the control of the Company, that the fair value of any reporting unit could decrease in the future and result in an impairment to goodwill.

Allowance for Doubtful Accounts. We estimate our allowance for doubtful accounts based on an analysis of historical collection activity and specific identification of overdue accounts. Factors that may affect this estimate include (1) changes in the financial positions of significant customers and (2) a decline in commodity prices that could affect the entire customer base.

Litigation and Self-Insured Risk Reserves. We estimate our reserves related to litigation and self-insured risk based on the facts and circumstances specific to the litigation and self-insured risk claims and our past experience with similar claims. The actual outcome of litigation and insured claims could differ significantly from estimated amounts. As discussed in " Self-Insured Risk Accruals" above with respect to our critical accounting policies, we maintain accruals on our balance sheet to cover self-insured retentions. These accruals are based on certain assumptions developed using third-party data and historical data to project future losses. Loss estimates in the calculation of these accruals are adjusted based upon actual claim settlements and reported claims.

Fair Value of Assets Acquired and Liabilities Assumed. We estimate the fair value of assets acquired and liabilities assumed in business combinations, which involves the use of various assumptions. These estimates may be affected by such factors as changing market conditions, technological advances in the industry or changes in regulations governing the industry. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair value of property and equipment, intangible assets and the resulting amount of goodwill, if any. We test annually for impairment of the goodwill and intangible assets with indefinite useful lives recorded in business combinations. This requires us to estimate the fair values of our own assets and liabilities at the reporting unit level. Therefore, considerable judgment, similar to that described above in connection with our estimation of the fair value of an acquired company, is required to assess goodwill and certain intangible assets for impairment.

Cash Flow Estimates. Our estimates of future cash flows are based on the most recent available market and operating data for the applicable asset or reporting unit at the time the estimate is made. Our cash flow estimates are used for asset impairment analyses.

Stock-Based Compensation. We have historically compensated our directors, executives and employees through the awarding of stock options and restricted stock. We accounted for stock option and restricted stock awards in 2011, 2012 and 2013 using a grant date fair-value based method, resulting in compensation expense for stock-based awards being recorded in our consolidated statements of income. For performance-based restricted stock awards, compensation expense is recognized in our financial statements based on their grant date fair value. We utilize (i) the closing stock price on the date of the grant to determine the fair value of vesting restricted stock awards and (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards with a combination of market and service vesting criteria. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The expected volatility utilized in the model was estimated using our historical volatility and the historical volatilities of our peer companies. The risk free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant. Stock options have not been issued since 2007 but are valued on the grant date using Black-Scholes-Merton option pricing model and restricted stock issued is valued based on the fair value of our common stock at the grant date. In addition, judgment is required in estimating the amount of stock-based awards that are expected to be forfeited. Because the determination of these various assumptions is subject to significant management judgment and different assumptions could result in material differences in amounts recorded in our consolidated financial statements, management believes that accounting estimates related to the valuation of stock options are critical.

Income Taxes. The amount and availability of our loss carryforwards (and certain other tax attributes) are subject to a variety of interpretations and restrictive tests. The utilization of such carryforwards could be limited or lost upon certain changes in ownership and the passage of time. Accordingly, although we believe substantial loss carryforwards are available to us, no assurance can be given concerning the realization of such loss carryforwards, or whether or not such loss carryforwards will be available in the future.

Results of Operations

The results of operations between periods may not be comparable, primarily due to fluctuations in the oil and natural gas industry throughout 2011, 2012 and 2013, as well as the Company’s growth in asset base during 2011 and 2012. The asset base slightly decreased during 2013.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Revenues. Revenues decreased by 8% to $1.3 billion in 2013 from $1.4 billion in 2012. This decrease was primarily due to relatively flat demand by our customers for our services and increased competition, which affected the rates we can charge for services.

Completion and remedial services revenues decreased by 14% % to $501.1 million in 2013 as compared to $586.1 million in 2012. The decrease in revenue between these periods was primarily due to lower pumping revenues driven by lower pricing for our services caused by high levels of competition. Total hydraulic horsepower was 297,000 and 291,000 at December 31, 2013 and December 31, 2012, respectively.

Fluid services revenues decreased by 2% to $343.9 million in 2013 compared to $352.2 million in 2012. This decrease was partially offset by an increase in our truck fleet in 2013. Revenue per fluid service truck decreased 7% to $353,000 in 2013 compared to $380,000 in 2012, due to the competitive market and pricing for our services and lower non-trucking revenues such as frac tank rentals and construction revenues. Our weighted average number of fluid service trucks increased 5% to 975 in 2013 from 926 in 2012, which reflects the expansion of our truck fleet.

Well servicing revenues decreased by 3% to $363.4 million in 2013 compared to $376.3 million in 2012. This decrease in revenue was due to the decrease in rig utilization to 71% during 2013 from 73% during 2012, reflecting the competitive market in oil-dominated areas. Our weighted average number of well servicing rigs decreased to 425 during 2013 compared to 429 in 2012. We experienced an increase of 2% in revenue per rig hour to $ 404 during 2013 from $397 during 2012, due to increased revenues from plugging and abandonment units and barge rigs, which both work for higher rates than workover rigs.

Contract drilling revenues decreased by 10% to $54.5 million in 2013 compared to $60.3 million in 2012. The number of rig operating days decreased to 3,310 in 2013 compared to 3,823 in 2012, resulting in a decrease in rig utilization from 87% in 2012 to 76% in 2013. The decrease was driven by inconsistent utilization in the 1000-horsepower vertical drilling market during 2013. The average revenue per rig day increased from $15,800 in 2012 to $16,500 in 2013 due to higher utilization of our larger horsepower rigs.

Direct Operating Expenses. Direct operating expenses, which primarily consist of labor costs, including workers' compensation and health insurance, and maintenance and repair costs, decreased by 4% to $868.1 million in 2013 from $902.6 million in 2012. This decrease was due to the lower activity levels in all of our segments.

Direct operating expenses for the completion and remedial services segment decreased by 8% to $327.5 million in 2013 as compared to $358.0 million in 2012, due primarily to decreased activity levels. Segment profits decreased to 35% of revenues in 2013 compared to 39% in 2012, due to a decrease in pricing for our services, caused by increased competition in all operating areas, with relatively flat direct costs.

Direct operating expenses for the fluid services segment increased by 1% to $239.2 million in 2013 as compared to $236.6 million in 2012. Segment profits were 30% of revenues in 2013 and 33% of revenues in 2012, due to decreases in pricing for our trucking services, lower frac tank rentals, and increased fuel and propane prices in 2013.

Direct operating expenses for the well servicing segment decreased by 1% to $265.1 million in 2013 as compared to $268.2 million in 2012, due primarily to the 4% decrease in rig hours to 861,200 in 2013 from 893,200 in 2012. Segment profits decreased to 27% of revenues in 2013 compared to 29% in 2012, due to lower operating activity.

Direct operating expenses for the contract drilling segment decreased by 9% to $36.3 million in 2013 as compared to $39.8 million in 2012. Segment profits were 33% of revenues in 2013 compared to 34% in 2012.

General and Administrative Expenses. General and administrative expenses decreased by 6% to $171.4 million in 2013 from $183.3 million in 2012. The decrease was primarily due to decreased personnel and incentive compensation costs of $7.1 million in 2013 from 2012, primarily due to relocation cost. The relocation costs, including employee-related relocation costs, were approximately $7.9 million in 2012. In 2012 and 2013, we also expensed $6.7 million and $2.1 million, respectively, for a Texas sales and use tax assessment which was paid out in 2013. In July 2013, we expensed $8.0 million related to a settlement of a case stemming from an accident that occurred in 2008. G&A expense included $11.8 million and $12.9 million of stock-based compensation expense in 2013 and 2012, respectively.

Depreciation and Amortization Expenses. Depreciation and amortization expenses were $209.7 million in 2013, as compared to $187.1 million in 2012, reflecting the increase in the size of and investment in our asset base. We invested $21.5 million for acquisitions, $50.6 million for capital leases and an additional $137.0 million for cash capital expenditures in 2013.

Loss on Early Extinguishment of Debt. In the fourth quarter of 2012, we recorded a charge of $7.9 million for the retirement of our $225.0 million 7.125% senior notes due 2016 issued in April 2006.

Interest Expense. Interest expense increased by 8% to $67.2 million in 2013 from $62.4 million in 2012. The increased expense was due to a full year impact of interest expense for the issuance of $300.0 million of 7.75% senior notes due 2022 in the fourth quarter of 2012.

Income Tax Expense. Income tax benefit of $19.7 million in 2013, as compared to tax expense of $10.9 million in 2012. Our effective tax rate was approximately 35% in 2013 and 34% in 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Revenues. Revenues increased by 17% to $1.4 billion in 2012 from $1.2 billion in 2011. This increase was primarily due to the recovery of the oil and gas industry in 2011 and overall stabilization through most of 2012, notwithstanding lower natural gas commodity prices. Our acquisitions in the second half of 2011 and during 2012 also increased our revenues, with the Maverick Companies acquisition in the third quarter of 2011 adding incremental revenue of $68.4 million in 2012.

Completion and remedial services revenues increased by 9% to $586.1 million in 2012 as compared to $537.1 million in 2011. The increased revenues are primarily due to a full year of revenues from the Maverick Companies acquisition in the third quarter of 2011, which added approximately $68.4 million of incremental segment revenue. The incremental revenue from the Maverick Companies was offset by a decline in utilization and pricing in our stimulation services in the second half of 2012. Total hydraulic horsepower was 291,000 and 271,000 at December 31, 2012 and December 31, 2011, respectively.

Fluid services revenues increased by 6% to $352.2 million in 2012 compared to $332.0 million in 2011. Our weighted average number of fluid service trucks increased 9% to 926 in 2012 from 850 in 2011, which reflects the expansion of our truck and frac tank fleets. Revenue per fluid service truck decreased 3% to $380,000 in 2012 compared to $391,000 in 2011, due to the competitive market and pricing for our services and lower non-trucking revenues such as frac tank rentals and skim oil sales.

Well servicing revenues increased by 13% to $376.3 million in 2012 compared to $333.1 million in 2011. This increase in revenue was due to the increase in rig utilization to 73% during 2012 from 70% during 2011, reflecting the continued high activity levels in oil-dominated areas. We also experienced an increase of 4% in revenue per rig hour to $397 during 2012 from $380 during 2011, due to increased revenues from plugging and abandonment units acquired during the year, which work for higher rates than workover rigs. Our average number of well servicing rigs increased to 429 during 2012 compared to 414 in 2011, primarily due to acquisitions.

Contract drilling revenues increased by 47% to $60.3 million in 2012 compared to $41.1 million in 2011. The number of rig operating days increased to 3,823 in 2012 compared to 2,889 in 2011. This increase was due to the addition of two drilling rigs during 2012.

Direct Operating Expenses. Direct operating expenses, which primarily consist of labor costs, including workers' compensation and health insurance, and maintenance and repair costs, increased by 18% to $902.6 million in 2012 from $766.1 million in 2011. This increase was due to the higher activity levels in all of our segments.

Direct operating expenses for the completion and remedial services segment increased by 20% to $358.0 million in 2012 as compared to $297.3 million in 2011, due primarily to increased activity levels as well as a full year of the Maverick Companies acquisition. Segment profits decreased to 39% of revenues in 2012 compared to 45% in 2011, due to a decrease in pricing utilization for our services, caused by increased competition in all operating areas, with relatively flat direct costs.

Direct operating expenses for the fluid services segment increased by 12% to $236.6 million in 2012 as compared to $212.0 million in 2011, due to higher activity levels. Segment profits were 33% of revenues in 2012 and 36% of revenues in 2011, due to decreases in pricing for our trucking services and lower frac tank rental revenues.

Direct operating expenses for the well servicing segment increased by 17% to $268.2 million in 2012 as compared to $228.7 million in 2011, due primarily to the 8% increase in rig hours to 893,200 in 2012 from 829,600 in 2011. Segment profits decreased to 29% of revenues in 2012 compared to 31% in 2011, due to higher labor and other direct operating costs partially offset by improved utilization of assets.

Direct operating expenses for the contract drilling segment increased by 41% to $39.8 million in 2012 as compared to $28.2 million in 2011 due primarily to a 32% increase in rig operating days in 2012. Segment profits were 34% of revenues in 2012 compared to 31% in 2011, due primarily to increased dayrates from the larger rigs added in 2012.

General and Administrative Expenses. General and administrative (G&A) expenses increased by 27% to $183.3 million in 2012 from $144.5 million in 2011. The increase was primarily due to increased personnel and incentive compensation costs, including payroll taxes, the relocation of our corporate headquarters in the second half of 2012 and the full-year effect of the general and administrative expense from the Maverick Companies acquisition that was completed in July 2011. We estimated that relocation costs, including employee-related relocation costs, were approximately $7.9 million. The Texas sales and use tax assessment also increased general and administrative expenses by $6.7 million. G&A expense included $12.9 million and $9.5 million of stock-based compensation expense in 2012 and 2011, respectively.

Depreciation and Amortization Expenses. Depreciation and amortization expenses were $187.1 million in 2012, as compared to $154.3 million in 2011, reflecting the increase in the size of and investment in our asset base. We invested $84.9 million for acquisitions, $67.2 million for capital leases and an additional $171.4 million for cash capital expenditures in 2012.

Loss on Early Extinguishment of Debt. In the fourth quarter of 2012, we recorded a charge of $7.9 million for the retirement of our $225.0 million 7.125% senior notes due 2016 issued in April 2006. In 2011, we recorded a loss of $49.4 million for the retirement of our $225.0 million 11.625% senior secured notes and the retirement of our previous $30.0 million revolving credit facility.

Interest Expense. Interest expense increased by 16% to $62.4 million in 2012 from $53.9 million in 2011. The increased expense was due to a full year impact of interest expense for the issuance of an aggregate of $475.0 million of 7.75% senior notes due 2019 in the first half of 2011 and the issuance of $300.0 million of 7.75% senior notes due 2022 in the fourth quarter of 2012.

Income Tax Expense. Income tax expense was $10.3 million in 2012, as compared to a tax expense of $30.9 million in 2011. Our effective tax rate was approximately 34% in 2012 and our effective tax rate was approximately 40% in 2011. The decrease in the effective tax rate was primarily due to a $1.9 million tax refund from the state of Texas in 2012 and a charge associated with the redemption of 11.625% senior secured notes in 2011.

Liquidity and Capital Resources

Currently, our primary capital resources are net cash flows from our operations and utilization of capital leases and our $250.0 million revolving credit facility. As of December 31, 2013, we had cash and cash equivalents of $111.5 million compared to $134.6 million as of December 31, 2012. We have utilized, and expect to utilize in the future, bank and capital lease financing and sales of equity to obtain capital resources. When appropriate, we will consider public or private debt and equity offerings and non-recourse transactions to meet our liquidity needs.

Net Cash Provided by Operating Activities

Cash flow from operating activities was $165.6 million for the year ended December 31, 2013 as compared to $303.7 million in 2012 and $279.5 million in 2011. The decrease in 2013 was primarily due to a decrease in operating income and a decrease in deferred tax liability due to decreased profitability and a decrease in accounts payable. The increase in 2012 was due primarily to the collection of accounts receivable generated in prior periods and an increase in the deferred tax liability partially offset by an increase in income tax payable due to increased profitability.

Capital Expenditures

Capital expenditures are the main component of our investing activities. Cash capital expenditures (including acquisitions) for 2013 were $158.4 million as compared to $256.4 million in 2012, and $440.2 million in 2011. Cash capital expenditures decreased in 2013 from 2012 due to the decrease in acquisitions to $21.5 million from $85.0 million in 2012. Cash capital expenditures decreased in 2012 from 2011 due to the decrease in acquisitions from $218.3 million in 2011 to $84.9 million in 2012. Through our capital lease program, we also added assets of approximately $50.6 million, $67.2 million and $57.7 million in 2013, 2012 and 2011, respectively.

In 2014, we have currently planned capital expenditures of approximately $150 million and capital leases of $55 million. We do not budget acquisitions in the normal course of business, and we regularly engage in discussions related to potential acquisitions related to the well services industry.

Corporate Office Relocation

On June 4, 2012, we announced that we were moving our corporate headquarters to Fort Worth, Texas from Midland, Texas. A transition plan was developed to provide for the move of the corporate operations, including relocation benefits for employees who were transferred, and severance and retention benefits for employees who did not continue with us after the move. As part of the relocation, severance and retention plans, we recognized $7.9 million in general and administrative expense for the year ended December 31, 2012.

Capital Resources and Financing

Our current primary capital resources are cash flow from our operations, our $250.0 million revolving credit facility, the ability to enter into capital leases and a cash balance of $111.5 million at December 31, 2013. In 2013, we financed activities in excess of cash flow from operations primarily through the use of bank debt and capital leases.

We have significant contractual obligations in the future that will require capital resources. Our primary contractual obligations are (1) our long-term debt, (2) interest on long-term debt, (3) our capital leases, (4) our operating leases, (5) our asset retirement obligations and (6) our other long-term liabilities. The following table outlines our contractual obligations as of December 31, 2013 (in thousands):

	Obligations Due in Periods Ended December 31,				
Contractual Obligations	Total	2014	2015-2016	2017-2018	Thereafter
Long-term debt (excluding capital leases)	$ 775,000	$ -	$ -	$ -	$ 775,000
Interest on long-term debt	430,125	60,063	120,125	120,125	129,812

Capital leases	111,626	41,394	56,953	13,164	115
Operating leases	34,315	9,130	12,965	4,216	8,004
Other long-term liabilities	5,831	633	1,879	899	2,420
Total	$ 1,356,897	$ 111,220	$ 191,922	$ 138,404	$ 915,351

Our long-term debt as of December 31, 2013, excluding capital leases, consisted of our $300.0 million 7.75% Senior Notes due 2022 and our $475.0 million 7.75% Senior Notes due 2019. Interest on long-term debt relates to our future contractual interest obligations on our Senior Notes. Our capital leases relate primarily to light-duty and heavy-duty vehicles and trailers. Our operating leases relate primarily to real estate.

Our ability to access additional sources of financing will be dependent on our operating cash flows and demand for our services, which could be negatively impacted due to the extreme volatility of commodity prices.

7.75% Senior Notes due 2019

On February 15, 2011, we issued $275.0 million aggregate principal amount of 7.75% Senior Notes due 2019 (the “2019 Notes”). On June 13, 2011, we issued an additional $200.0 million aggregate principal amount of 2019 Notes, resulting in outstanding 2019 Notes with an aggregate principal amount of $475.0 million. The 2019 Notes are jointly and severally, and unconditionally, guaranteed on a senior unsecured basis by all of our current subsidiaries, other than three immaterial subsidiaries. The 2019 Notes and the guarantees rank (1) equally in right of payment with any of our and the subsidiary guarantors’ existing and future senior indebtedness, including our existing 7.75% Senior Notes due 2022 and the related guarantees, and (2) effectively junior to all existing or future liabilities of our subsidiaries that do not guarantee the 2019 Notes and to our and the subsidiary guarantors' existing or future secured indebtedness to the extent of the value of the collateral therefor.

The 2019 Notes and guarantees were offered and sold in private transactions in accordance with Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act").

The purchase price for the $275.0 million of 2019 Notes issued on February 15, 2011 was 100.000% of their principal amount, and the purchase price for the $200.0 million of 2019 Notes issued on June 13, 2011 was 101.000%, plus accrued interest from February 15, 2011. We received net proceeds from the issuance of the 2019 Notes of approximately $464.6 million after premiums and offering expenses. We used a portion of the net proceeds from the February 2011 offering to fund our tender offer and consent solicitation for our 11.625% Senior Secured Notes and to redeem any of the Senior Secured Notes not purchased in the tender offer. We used the net proceeds from the June 2011 offering to fund the $186.3 million purchase price for the Maverick Companies acquisition completed in July 2011 and for general corporate purposes.

The 2019 Notes and guarantees were issued pursuant to an indenture dated as of February 15, 2011 (the "2019 Notes Indenture"), by and among Basic, the guarantors party thereto and Wells Fargo Bank, N.A., as trustee. Interest on the 2019 Notes accrues from and including February 15, 2011 at a rate of 7.75% per year. Interest on the 2019 Notes is payable semi-annually in arrears on February 15 and August 15 of each year. The 2019 Notes mature on February 15, 2019.

The 2019 Notes Indenture contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to:

- incur additional indebtedness;
- pay dividends or repurchase or redeem capital stock;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates;
- limit dividends or other payments by our restricted subsidiaries to us; and
- sell assets or consolidate or merge with or into other companies.

These and other covenants that are contained in the 2019 Notes Indenture are subject to important exceptions and qualifications set forth in the 2019 Notes Indenture. At December 31, 2013, we were in compliance with the restrictive covenants under the 2019 Notes Indenture.

We may, at our option, redeem all or part of the 2019 Notes, at any time on or after February 15, 2015, at a redemption price equal to 100% of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest to the date of redemption.

At any time before February 15, 2014, we, at our option, may redeem up to 35% of the aggregate principal amount of the 2019 Notes issued under the 2019 Notes Indenture with the net cash proceeds of one or more qualified equity offerings at a redemption price of 107.750% of the principal amount of the 2019 Notes to be redeemed, plus accrued and unpaid interest to the date of redemption, as long as:

•at least 65% of the aggregate principal amount of the 2019 Notes issued under the 2019 Notes Indenture remains outstanding immediately after the occurrence of such redemption; and

•such redemption occurs within 90 days of the date of the closing of any such qualified equity offering.

In addition, at any time before February 15, 2015, we may redeem some or all of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes, plus an applicable premium and accrued and unpaid interest to the date of redemption.

Following a change of control, as defined in the 2019 Notes Indenture, we will be required to make an offer to repurchase all or a portion of the 2019 Notes at 101% of their principal amount, plus accrued and unpaid interest to the date of repurchase.

7.75% Senior Notes due 2022

On October 16, 2012, we issued $300.0 million aggregate principal amount of 7.75% Senior Notes due 2022 (the “2022 Notes”). The 2022 Notes are jointly and severally, and unconditionally, guaranteed on a senior unsecured basis initially by all of our current subsidiaries other than three immaterial subsidiaries. The 2022 Notes and the guarantees rank (1) equally in right of payment with any of our and the subsidiary guarantors’ existing and future senior indebtedness, including our existing 2019 Notes and the related guarantees, and (2) effectively junior to all existing or future liabilities of our subsidiaries that do not guarantee the 2022 Notes and to our and the subsidiary guarantors’ existing or future secured indebtedness to the extent of the value of the collateral therefor.

The 2022 Notes and the guarantees were offered and sold in private transactions in accordance with Rule 144A and Regulation S under the Securities Act. We received net proceeds from the issuance of the 2022 Notes of approximately $293.3 million after discounts and offering expenses. We used a portion of the net proceeds from the offering to fund our pending tender offer and consent solicitation for our 7.125% Senior Notes due 2016 (The “2016 Notes”) and to redeem any of the 2016 Notes not purchased in the tender offer. The remainder of the net proceeds were used for general corporate purposes.

The 2022 Notes and the guarantees were issued pursuant to an indenture dated as of October 16, 2012 (the “2022 Notes Indenture”), by and among us, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee. Interest on the 2022 Notes accrues from and including October 16, 2012 at a rate of 7.75% per year. Interest on the 2022 Notes is payable semi-annually in arrears on April 15 and October 15 of each year, commencing on April 15, 2013. The 2022 Notes mature on October 15, 2022.

The 2022 Notes Indenture contains covenants that, among other things, limit our ability and the ability of certain of our subsidiaries to:

• incur additional indebtedness;

• pay dividends or repurchase or redeem capital stock;

• make certain investments;

• incur liens;

• enter into certain types of transactions with affiliates;

• limit dividends or other payments by our restricted subsidiaries to us; and

• sell assets or consolidate or merge with or into other companies.

These and other covenants that are contained in the 2022 Notes Indenture are subject to important exceptions and qualifications set forth in the 2022 Indenture. At December 31, 2013, we were in compliance with the restrictive covenants under the 2022 Notes Indenture.

We may, at our option, redeem all or part of the 2022 Notes, at any time on or after October 15, 2017, at a redemption price equal to 100% of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest to the date of redemption.

At any time before October 15, 2015, we, at our option, may redeem up to 35% of the aggregate principal amount of the 2022 Notes issued under the 2022 Notes Indenture with the net cash proceeds of one or more qualified equity offerings at a redemption price of 107.750% of the principal amount of the 2022 Notes to be redeemed, plus accrued and unpaid interest to the date of redemption, as long as:

• at least 65% of the aggregate principal amount of the 2022 Notes issued under the 2022 Notes Indenture remains

outstanding immediately after the occurrence of such redemption; and

•such redemption occurs within 90 days of the date of the closing of any such qualified equity offering.

In addition, at any time before October 15, 2017, we may redeem some or all of the 2022 Notes at a redemption price equal to 100% of the principal amount of the 2022 Notes, plus an applicable premium and accrued and unpaid interest to the date of redemption.

Following a change of control, as defined in the 2022 Notes Indenture, we will be required to make an offer to repurchase all or a portion of the 2022 Notes at 101% of their principal amount, plus accrued and unpaid interest to the date of repurchase.

Revolving Credit Facility

On February 15, 2011, in connection with the initial offering of 2019 Notes, we terminated our previous $30.0 million secured revolving credit facility with Capital One, National Association, and entered into a credit agreement (the “Credit Agreement”) providing for a new $165.0 million Revolving Credit Facility with Merrill Lynch, Pierce, Fenner & Smith Incorporated and Capital One, National Association, as joint lead arrangers and joint book managers, the lenders party thereto and Bank of America, N.A., as administrative agent. The Credit Agreement includes an accordion feature whereby the total credit available to us can be increased by up to $100.0 million under certain circumstances, subject to additional lender commitments. The obligations under the Credit Agreement are guaranteed on a joint and several basis by each of our current subsidiaries, other than three immaterial subsidiaries, and are secured by substantially all of our and our subsidiary guarantors’ assets as collateral under a related Security Agreement (the “Security Agreement”). As of December 31, 2013, the non-guarantor subsidiaries held no assets and performed no operations. On July 15, 2011, we exercised the accordion feature and amended the Credit Agreement to increase our total credit available from $165.0 million to $225.0 million. On April 5, 2012, we amended the Credit Agreement to increase the aggregate amount of

commitments thereunder to $250.0 million. On October 1, 2012, we further amended the Credit Agreement to permit the transactions contemplated by the offering of 2022 Notes and tender offer and redemption of 2016 Notes. On August 29, 2013, we further amended the Credit Agreement to amend the required leverage ratios.

Borrowings under the Credit Agreement mature on January 15, 2016, and we have the ability at any time to prepay the Credit Agreement without premium or penalty. At our option, advances under the Credit Agreement may be comprised of (i) alternate base rate loans, at a variable base interest rate plus a margin ranging from 1.50% to 2.50% based on our leverage ratio or (ii) Eurodollar loans, at a variable base interest rate plus a margin ranging from 2.50% to 3.50% based on our leverage ratio. We will pay a commitment fee equal to 0.50% on the daily unused amount of the commitments under the Credit Agreement.

The Credit Agreement contains various covenants that, subject to agreed upon exceptions, limit our ability and the ability of certain of our subsidiaries to:

•incur indebtedness;

•grant liens;

•enter into sale and leaseback transactions;

•make loans, capital expenditures, acquisitions and investments;

•change the nature of business;

•acquire or sell assets or consolidate or merge with or into other companies;

•declare or pay dividends;

•enter into transactions with affiliates;

•enter into burdensome agreements;

•prepay, redeem or modify or terminate other indebtedness;

•change accounting policies and reporting practices; and

•amend organizational documents.

The Credit Agreement also contains covenants that, among other things, limit the amount of capital contributions we may make and require us to maintain specified ratios or conditions as follows:

· a minimum consolidated interest coverage ratio of not less than 2.50 to 1.00;

· a maximum consolidated leverage ratio as follows:

o for the four fiscal quarters ending September 30, 2013 and December 31, 2013, a maximum consolidated leverage ratio not to exceed 4.50 to 1.00;

o for the four fiscal quarters ending March 31, 2014 and June 30, 2014, a maximum consolidated leverage ratio not to exceed 4.25 to 1.00; and

o for the four fiscal quarters ending September 30, 2014 and each fiscal quarter thereafter, a maximum consolidated leverage ratio not to exceed 4.00 to 1.00; and

· a maximum consolidated senior secured leverage ratio as follows:

o for the four fiscal quarters ending September 30, 2013 through June 30, 2014, a maximum consolidated senior secured leverage ratio not to exceed 1.75 to 1.00; and

o for the four fiscal quarters ending September 30, 2014 and each fiscal quarter thereafter, a maximum consolidated senior secured leverage ratio not to exceed 2.00 to 1.00.

If an event of default occurs under the Credit Agreement, then the lenders may (i) terminate their commitments under the Credit Agreement, (ii) declare any outstanding loans under the Credit Agreement to be immediately due and payable after applicable grace periods and (iii) foreclose on the collateral secured by the Security Agreement.

We had no borrowings and $38.0 million of letters of credit outstanding under the Credit Agreement as of December 31, 2013, giving us $212.0 million of available borrowing capacity. At December 31, 2013, we were in compliance with our covenants under the Credit Agreement.

Other Debt

We have a variety of other capital leases and notes payable outstanding that is generally customary in our business. None of these debt instruments is material individually. Our leases with Banc of America Leasing & Capital, LLC requires us to maintain a minimum debt service coverage ratio of 1.05 to 1.00. As of December 31, 2013, we had total capital leases of approximately $111.6 million.

Losses on Extinguishment of Debt

In October 2012, upon the retirement of the 2016 Notes, we wrote off unamortized debt issuance costs of approximately $1.8 million. Basic also paid a premium of $6.1 million to the holders of the 2016 Notes for the early termination of the notes. In February 2011, upon the retirement of the 11.625% Senior Secured Notes and the termination of our previous $30.0 million revolving credit facility, we wrote off unamortized debt issuance costs of approximately $3.9 million and unamortized discount of $9.2 million. We also paid a premium of $36.2 million to the holders of the 11.625% Senior Secured Notes for the early termination of the notes.

Preferred Stock

At December 31, 2013 and December 31, 2012, we had 5,000,000 shares of $.01 par value preferred stock authorized, of which none was designated, issued or outstanding.

Other Matters

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Net Operating Losses

As of December 31, 2013, we had approximately $121.3 million of NOL carryforwards.

Recent Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet" ("ASU 2011-11"). The standard amends and expands disclosure requirements about balance sheet offsetting and related arrangements. ASU 2011-11 became effective for Basic on January 1, 2013. The adoption of this standard did not have a material impact to its results of operations, financial position or liquidity as a result of this guidance.

In July 2012, the FASB issued ASU No. 2012-02, "Intangibles — Goodwill and Other: Testing Indefinite-Lived Intangible Assets for Impairment" ("ASU 2012-02"). ASU 2012-02 allows a qualitative assessment of whether it is more likely than not that the indefinite-lived intangible asset's fair value is less than its carrying amount before applying the quantitative impairment test. If it is more likely than not that the fair value of an indefinite-lived intangible asset is less than its carrying amount, then the impairment test for that indefinite-lived intangible asset would be performed. ASU 2012-02 is effective for annual and interim impairment tests performed for indefinite-lived intangible assets for fiscal years beginning after September 15, 2012 and early adoption is permitted. Basic adopted this accounting standard update early, and although it has changed the process Basic uses to determine if indefinite-lived intangible assets are impaired, it has not had a material impact on Basic's consolidated financial statements.

In July 2013, the FASB issued ASU No. 2013-11, "Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exist." ASU 2013-11 reduces diversity in proactive by providing guidance on the presentation of unrecognized tax benefits and will better reflect the manner in which an entity would settle at the reporting date any additional income taxes that would result from the disallowance of a tax position when net operating loss carryforwards, similar tax losses, or tax credit carryforwards exist. ASU 2013-11 becomes effective for Basic on January 1, 2014 and Basic does not believe it will have a material impact on its consolidated financial statements.

Impact of Inflation on Operations

Management is of the opinion that inflation has not had a significant impact on our business.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

As of December 31, 2013, we had no borrowings outstanding under any agreements with market risk sensitive instruments, and were not party to any other material market risk sensitive instruments.

ITEM 8.FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Basic Energy Services, Inc.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Basic Energy Services, Inc. ("Basic" or the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for the Company. As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Exchange Act of 1934, as amended), internal control over financial reporting is a process designed by, or under the supervision of Basic's principal executive and principal financial officers and effected by its Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles.

The Company's internal control over financial reporting is supported by written policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the Company's transactions and dispositions of the Company's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorization of the Company's management and directors; 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 consolidated 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 connection with the preparation of the Company's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Company's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2013, the Company's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The Company acquired Atlas Environmental Consulting, Inc. and Atlas Oilfield Construction Company, LLC, Petroleum Water Solutions, LLC, and Karnes Water Management, LLC (collectively, the "Acquisitions") during 2013, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2013, the Acquisitions' internal control over financial reporting associated with total assets of $21.5 million and total revenues of $10.6 million included in the consolidated financial statements of Basic Energy Services, Inc. and subsidiaries as of and for the year ended December 31, 2013.

KPMG LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this report, has issued an attestation report on the effectiveness of internal control over financial reporting.

/s/ Thomas M. Patterson	/s/ Alan Krenek
Thomas M. Patterson	Alan Krenek
Chief Executive Officer	Chief Financial Officer

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Basic Energy Services, Inc.:

We have audited Basic Energy Services, Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Basic Energy Services, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company'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, Basic Energy Services, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Basic Energy Services, Inc. acquired Atlas Environmental Consulting, Inc., Atlas Oilfield Construction Company, LLC., Petroleum Water Solutions, LLC, and Karnes Water Management, LLC (collectively, the "Acquisitions") during 2013, and management excluded from its assessment of the effectiveness of Basic Energy Services, Inc.'s internal control over financial reporting as of December 31, 2013, the Acquisitions' internal control over financial reporting associated with total assets of $21.5 million and total revenues of $10.6 million included in the consolidated financial statements of Basic Energy Services, Inc. and subsidiaries as of and for the year ended December 31, 2013. Our audit of internal control over financial reporting of Basic Energy Services, Inc. also excluded an evaluation of the internal control over financial reporting of the Acquisitions.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Basic Energy Services, Inc. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2013, and our report dated February 24, 2014 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Dallas, Texas

February 24, 2014

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Basic Energy Services, Inc.:

We have audited the accompanying consolidated balance sheets of Basic Energy Services Inc. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three year period ended December 31, 2013. In connection with our audits of the consolidated financial statements, we also have audited financial statement schedule II. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules 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 Basic Energy Services, Inc. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present 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), Basic Energy Services, Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2014 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Dallas, Texas

February 24, 2014

Basic Energy Services, Inc.

Consolidated Balance Sheets

(in thousands, except share data)

	December 31, 2013	2012 (See Note 1)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 111,532	$ 134,565
Trade accounts receivable, net of allowance of $3,675 and $2,780, respectively	204,394	209,100
Accounts receivable - related parties	50	52
Income tax receivable	3,475	2,553
Inventories	34,240	40,230
Prepaid expenses	9,597	8,796
Other current assets	8,289	13,891
Deferred tax assets	31,436	32,201
Total current assets	403,013	441,388
Property and equipment, net	928,037	943,766
Deferred debt costs, net of amortization	16,145	18,733
Goodwill	110,914	105,836
Other intangible assets, net of amortization	77,555	82,762
Other assets	7,675	6,521
Total assets	$ 1,543,339	$ 1,599,006
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 45,508	$ 61,740
Accrued expenses	77,058	81,076
Current portion of long-term debt	41,394	38,235
Other current liabilities	688	306
Total current liabilities	164,648	181,357
Long-term debt, net of discount or premium on notes of $1,459 and $1,683 at December 31, 2013 and 2012, respectively	846,691	844,906
Deferred tax liabilities	164,306	185,101
Other long-term liabilities	22,407	15,232
Commitments and contingencies		
Stockholders' equity:		
Preferred stock; $.01 par value; 5,000,000 shares authorized; none designated or issued at December 31, 2013 and December 31, 2012, respectively	-	-
Common stock; $.01 par value; 80,000,000 shares authorized; 43,500,032 shares issued and 42,226,088 shares outstanding at December 31, 2013; and 43,500,032 shares issued and 41,721,229 shares outstanding at December 31, 2012	435	435
Additional paid-in capital	363,674	359,160
Retained earnings (deficit)	(6,726)	29,203
	(12,096)	(16,388)

Treasury stock, at cost 1,273,944 and 1,778,803 shares at December 31, 2013 and 2012, respectively		
Total stockholders' equity	345,287	372,410
Total liabilities and stockholder's equity	$ 1,543,339	$ 1,599,006

See accompanying notes to consolidated financial statements.

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Basic Energy Services, Inc.

Consolidated Statements of Operations and Comprehensive Income (Loss)

(Dollars in thousands, except per share amounts)

	Years ended December 31		
	2013	2012 (See Note 1)	2011 (See Note 1)
Revenues:			
Completion and remedial services	$ 501,137	$ 586,070	$ 537,134
Fluid services	343,863	352,246	332,010
Well servicing	363,386	376,268	333,057
Contract drilling	54,518	60,300	41,054
Total revenues	1,262,904	1,374,884	1,243,255
Expenses:			
Completion and remedial services	327,540	357,960	297,276
Fluid services	239,154	236,588	211,959
Well servicing	265,058	268,219	228,723
Contract drilling	36,336	39,817	28,154
General and administrative, including stock-based compensation of $11,830, $12,855 and $9,487 in 2013, 2012 and 2011 respectively	171,439	183,274	144,485
Depreciation and amortization	209,747	187,083	154,341
Loss on disposal of assets	2,873	3,334	447
Total expenses	1,252,147	1,276,275	1,065,385
Operating income	10,757	98,609	177,870
Other income (expense):			
Interest expense	(67,207)	(62,438)	(53,886)
Interest income	53	83	1,587
Gain on bargain purchase	-	910	-
Loss on early extinguishment of debt	-	(7,942)	(49,366)
Other income	743	627	525
Income (loss) from continuing operations before income taxes	(55,654)	29,849	76,730
Income tax benefit (expense)	19,725	(10,263)	(30,894)
Net income (loss) available to common stockholders	$ (35,929)	$ 19,586	$ 45,836
Basic earnings (loss) per share of common stock:			
Net income (loss) available to common stockholders	$ (0.89)	$ 0.48	$ 1.14
Diluted earnings (loss) per share of common stock:			
Net income (loss) available to common stockholders	$ (0.89)	$ 0.47	$ 1.10

See accompanying notes to consolidated financial statements.

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Basic Energy Services, Inc.

Consolidated Statements of Stockholders' Equity

(in thousands, except share data)

	Common Stock Shares	Amount	Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Total Stockholders' Equity
Balance - December 31, 2010 (See Note 1)	42,394,809	$ 424	$ 336,402	$ (6,884)	$ (30,259)	$ 299,683
Issuances of restricted stock	-	-	(32)	5,783	(5,751)	-
Amortization of share based compensation	-	-	9,487	-	-	9,487
Purchase of treasury stock	-	-	-	(1,872)	-	(1,872)
Exercise of stock options	136,000	1	1,769	2,973	(209)	4,534
Net loss	-	-	-	-	45,836	45,836
Balance - December 31, 2011 (See Note 1)	42,530,809	425	347,626	-	9,617	357,668
Issuances of restricted stock	969,223	10	(526)	516	-	-
Amortization of share based compensation	-	-	12,855	-	-	12,855
Purchase of treasury stock	-	-	-	(18,497)	-	(18,497)
Exercise of stock options / vesting of restricted stock	-	-	(795)	1,593	-	798
Net income	-	-	-	-	19,586	19,586
Balance - December 31, 2012 (See Note 1)	43,500,032	435	359,160	(16,388)	29,203	372,410
Issuances of restricted stock	-	-	(6,751)	6,751	-	-
Amortization of share based compensation	-	-	11,830	-	-	11,830
Purchase of treasury stock	-	-	-	(3,605)	-	(3,605)
Exercise of stock options / vesting of restricted stock	-	-	(565)	1,146	-	581
Net income	-	-	-	-	(35,929)	(35,929)
Balance - December 31, 2013	43,500,032	$ 435	$ 363,674	$ (12,096)	$ (6,726)	$ 345,287

See accompanying notes to consolidated financial statements.

Basic Energy Services, Inc.

Consolidated Statements of Cash Flows

(in thousands)

	Years ended December 31, 2013	2012 (See Note 1)	2011 (See Note 1)
Cash flows from operating activities:			
Net income (loss)	$ (35,929)	$ 19,586	$ 45,836
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation and amortization	209,747	187,083	154,341
Gain on bargain purchase	-	(910)	-
Accretion on asset retirement obligation	112	110	124
Change in allowance for doubtful accounts	895	1,550	(1,848)
Amortization of deferred financing costs	3,102	2,831	2,349
Amortization of discount or (premium) on notes	(224)	(208)	6,385
Non-cash compensation	11,830	13,752	9,487
Loss on early extinguishment of debt (non-cash)	-	1,839	3,940
Payment of Premium and Consent for Senior Secured Notes	-	6,118	36,179
Loss on disposal of assets	2,873	3,334	447
Deferred income taxes	(20,030)	10,927	29,801
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	3,813	49,246	(88,863)
Inventories	5,990	(5,267)	(12,057)
Prepaid expenses and other current assets	(1,046)	564	(1,344)
Other assets	(1,154)	927	(2,853)
Accounts payable	(16,232)	4,720	12,140
Income tax receivable	(922)	(2,239)	79,166
Other liabilities	6,767	1,762	(6,665)
Accrued expenses	(4,004)	7,956	12,890
Net cash provided by operating activities	165,588	303,681	279,455
Cash flows from investing activities:			
Purchase of property and equipment	(136,950)	(171,440)	(221,839)
Purchase of mutual fund	-	(5,635)	-
Proceeds from sale of assets	19,863	12,069	20,843
Payments for other long-term assets	(1,132)	(817)	(624)
Payments for businesses, net of cash acquired	(21,467)	(84,939)	(218,347)
Net cash used in investing activities	(139,686)	(250,762)	(419,967)
Cash flows from financing activities:			

Proceeds from debt	-	300,000	498,850
Payments of debt	(45,397)	(266,949)	(278,696)
Premium on retirement of secured notes	-	(6,118)	(36,179)
Purchase of treasury stock	(3,605)	(18,497)	(1,872)
Tax withholding from exercise of stock options	(200)	(142)	(3,175)
Exercise of employee stock options	781	940	7,709
Deferred loan costs and other financing activities	(514)	(6,046)	(15,585)
Net cash provided by or (used) in financing activities	(48,935)	3,188	171,052
Net increase in cash and equivalents	(23,033)	56,107	30,540
Cash and cash equivalents - beginning of year	134,565	78,458	47,918
Cash and cash equivalents - end of year	$ 111,532	$ 134,565	$ 78,458

See accompanying notes to consolidated financial statements.

BASIC ENERGY SERVICES, INC.

Notes to Consolidated Financial Statements

December 31, 2013, 2012, and 2011

1.Nature of Operations

Basic Energy Services, Inc. ("Basic" or the "Company") provides a wide range of well site services to oil and natural gas drilling and producing companies, including completion and remedial services, fluid services and wellsite construction services, well servicing and contract drilling. These services are primarily provided by Basic's fleet of equipment. Basic's operations are concentrated in major United States onshore oil and natural gas producing regions located in Texas, New Mexico, Oklahoma, Kansas, Arkansas, Louisiana, Pennsylvania, West Virginia, Ohio, Wyoming, North Dakota, Colorado, Utah, Montana, and Kentucky.

Basic's reportable business segments are Completion and Remedial Services, Fluid Services, Well Servicing, and Contract Drilling. These segments are based on management's resource allocation and performance assessment in making decisions regarding the Company.

Revision of prior period financial statements and out-of-period adjustments

During the year ended December 31, 2013, we identified and corrected immaterial errors that originated in prior periods. We assessed the materiality of the errors in accordance with the SEC guidance on considering the effects of prior period misstatements based on an analysis of quantitative and qualitative factors. Based on this analysis, we determined that the errors were immaterial to each of the prior reporting periods affected. However, we have concluded that correcting the errors in our 2013 financial statements would materially understate results for the year ending December 31, 2013. Accordingly, we have reflected the correction of these prior period errors in the periods in which they originated and revised our consolidated balance sheet for the year ended December 31, 2012, our consolidated statement of operations and comprehensive income (loss), our consolidated statement of equity, and our consolidated statement of cash flows for the years ended December 31, 2012 and 2011.

These errors consisted mainly of individual deferred compensation plans and compensation expense related to share-based payments that should have been recorded in prior periods for retirement eligible employees. At December 31, 2010, retained deficit was reported as $27.5 million and was revised to $30.3 million. The effect of the immaterial corrections on the consolidated balance sheet as of December 31, 2012 are as follows (in thousands):

	As Reported	Correction	As Revised
Deferred tax assets	$ 29,113	$ 3,088	$ 32,201
Total current assets	438,300	3,088	441,388
Total assets	$ 1,595,918	$ 3,088	$ 1,599,006
Accrued expenses	$ 77,716	$ 3,360	$ 81,076
Other long-term liabilities	13,667	1,565	15,232
Total liabilities	1,221,671	4,925	1,226,596
Additional paid-in capital	355,687	3,473	359,160

Retained earnings	34,513	(5,310)	29,203
Total stockholders' equity	374,247	(1,837)	372,410
Total liabilities and stockholders' equity	$ 1,595,918	$ 3,088	$ 1,599,006

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The effect of the corrections on the Company's consolidated statements of operations and comprehensive income for the years ended December 31, 2012 and 2011 are as follows:

	As Reported	Correction	As Revised
December 31, 2012			
Total revenues	$ 1,374,884	$ —	$ 1,374,884
Total expenses	1,274,343	1,932	1,276,275
Operating income	100,541	(1,932)	98,609
Income (loss) from continuing operations before income taxes	31,781	(1,932)	29,849
Net income (loss)	$ 20,854	$ (1,268)	$ 19,586

	As Reported	Correction	As Revised
December 31, 2011			
Total revenues	$ 1,243,255	$ —	$ 1,243,255
Total expenses	1,063,164	2,221	1,065,385
Operating income	180,091	(2,221)	177,870
Income (loss) from continuing operations before income taxes	78,951	(2,221)	76,730
Net income (loss)	47,163	(1,327)	45,836

2.Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Basic and its wholly-owned subsidiaries. Basic has no variable interest in any other organization, entity, partnership, or contract. All intercompany transactions and balances have been eliminated.

Estimates, Risks and Uncertainties

Preparation of the accompanying consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Management uses historical and other pertinent information to determine these estimates. Actual results could differ from those estimates. Areas where critical accounting estimates are made by management include:

- Depreciation and amortization of property and equipment and intangible assets
- Impairment of property and equipment, goodwill and intangible assets
- Allowance for doubtful accounts
- Litigation and self-insured risk reserves

- Fair value of assets acquired and liabilities assumed

- Stock-based compensation

- Income taxes

Revenue Recognition

Completion and Remedial Services — Completion and remedial services consists primarily of pumping services focused on cementing, acidizing and fracturing, nitrogen units, coiled tubing units, snubbing units, thru-tubing and rental and fishing tools. Basic recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixed or determinable. Basic prices completion and remedial services by the hour, day, or project depending on the type of service performed. When Basic provides multiple services to a customer, revenue is allocated to the services performed based on the fair value of the services.

Fluid Services — Fluid services consists primarily of the sale, transportation, treatment, storage and disposal of fluids used in the drilling, production and maintenance of oil and natural gas wells, and well site construction and maintenance services. Basic recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixed or determinable. Basic prices fluid services by the job, by the hour or by the quantities sold, disposed of or hauled.

Well Servicing — Well servicing consists primarily of maintenance services, workover services, completion services, plugging and abandonment services and rig manufacturing and servicing. Basic recognizes revenue when services are performed, collection of the relevant receivables is probable, persuasive evidence of an arrangement exists and the price is fixed or determinable. Basic prices well servicing by the hour or by the day of service performed. Rig manufacturing revenue is recognized when the rig is accepted by the customer, based on the completed contract method by individual rig.

Contract Drilling — Contract drilling consists primarily of drilling wells to a specified depth using drilling rigs. Basic recognizes revenues based on either a “daywork” contract, in which an agreed upon rate per day is charged to the customer, a “footage” contract, in which an agreed upon rate is charged per the number of feet drilled, or a “turnkey” contract, in which an agreed upon single rate is charged for a drilled well.

Taxes assessed on sales transactions are presented on a net basis and are not included in revenue.

Cash and Cash Equivalents and Restricted Cash

Basic considers all highly liquid instruments purchased with a maturity of three months or less to be cash equivalents. Basic maintains its excess cash in various financial institutions, where deposits may exceed federally insured amounts at times.

Fair Value of Financial Instruments

The following is a summary of the carrying amounts and estimated fair values of our financial instruments as of December 31, 2013 and 2012. Fair value is defined as the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

Cash and cash equivalents, restricted cash, trade accounts receivable, accounts receivable-related parties, accounts payable and accrued expenses: These carrying amounts approximate fair value because of the short maturity of these instruments.

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Mutual Funds	$ -	$ -	$ 5,635	$ 5,594
7.75% Senior Notes due 2019, excluding premium	475,000	496,375	475,000	472,625
7.75% Senior Notes due 2022, excluding premium	300,000	309,750	300,000	292,500

Mutual Funds: The fair value of our mutual funds is based on matrix pricing at December 31, 2012. Matrix pricing is a mathematical technique widely used in the industry to value debt securities without relying exclusively on quoted prices for specific securities but rather by relying on the securities’ relationship to other benchmark quoted securities

7.75% Senior Notes due 2019, and 7.75% Senior Notes due 2022: The fair value of our long-term notes is based upon the quoted market prices at December 31, 2013 and December 31, 2012.

Inventories

For rental and fishing tools, inventories consisting mainly of grapples, controls, and drill bits are stated at the lower of cost or market, with cost being determined on the average cost method. Other inventories, consisting mainly of manufacturing raw materials, rig components, repair parts, drilling and completion materials and gravel, are held for use in the operations of Basic and are stated at the lower of cost or market, with cost being determined on the first-in, first-out (“FIFO”) method.

Property and Equipment

Property and equipment are stated at cost or at estimated fair value at acquisition date if acquired in a business combination. Expenditures for repairs and maintenance are charged to expense as incurred and additions and improvements that significantly extend the lives of the assets are capitalized. Upon sale or other retirement of depreciable property, the cost and accumulated depreciation and amortization are removed from the related accounts and any gain or loss is reflected in operations. All property and equipment are depreciated or amortized (to the extent of estimated salvage values) on the straight-line method and the estimated useful lives of the assets are as follows:

Buildings and improvements	20-30 years
Well service units and equipment	3-15 years
Fluid services equipment	5-10 years
Brine and fresh water stations	15 years
Frac/test tanks	10 years
Pumping equipment	5-10 years
Construction equipment	3-10 years
Contract drilling equipment	3-10 years
Disposal facilities	10-15 years
Vehicles	3-7 years
Rental equipment	2-15 years
Aircraft	5 years
Software and computers	3 years

The components of a well servicing rig generally require replacement or refurbishment during the well servicing rig's life and are depreciated over their estimated useful lives, which ranges from 3 to 15 years. The costs of the original components of a purchased or acquired well servicing rig are not maintained separately from the base rig.

Impairments

Long-lived assets, such as property, plant, and equipment, and purchased intangibles subject to amortization, are reviewed for impairment at a minimum annually, or whenever, in management's judgment 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 measured by a comparison of the carrying amount of such assets to estimated undiscounted future cash flows expected to be generated by the assets. Expected future cash flows and carrying values are aggregated at their lowest identifiable level, which is at the business segment level. If the carrying amount of such assets exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of such assets exceeds the fair value of the assets. Assets to be disposed of would be separately presented in the consolidated balance sheet and reported at the lower of the carrying amount or fair value less costs to sell, and are no longer depreciated. The assets and liabilities, if material, of a disposed group classified as held for sale would be presented separately in the appropriate asset and liability sections of the consolidated balance sheet. These assets are normally sold within a short period of time through a third party auctioneer.

Deferred Debt Costs

Basic capitalizes certain costs in connection with obtaining its borrowings, such as lender's fees and related attorney's fees. These costs are being amortized to interest expense using the effective interest method.

Deferred debt costs were approximately $23.2 million net of accumulated amortization of $7.2 million, and $22.6 million net of accumulated amortization of $4.1 million at December 31, 2013 and December 31, 2012, respectively. Amortization of deferred debt costs totaled approximately $3.1 million, $2.8 million and $2.3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Basic recorded a charge of $1.8 million during the fourth quarter of 2012 related to the write-off of debt costs associated with its 2016 Notes. On October 16, 2012, Basic completed the closing of an early tender for approximately $223.3 million of the 2016 Notes and delivered to the trustee amounts required to satisfy and discharge remaining obligations for the outstanding notes. Additionally, on October 16, 2012, Basic incurred $7.0 million of deferred debt costs associated with the issuance of 7.75% Senior Notes due 2022.

Basic recorded a charge of $3.9 million during the first quarter of 2011 related to the write-off of debt costs associated with its 11.625% Senior Secured Notes and $30.0 million revolving credit facility. On February 15, 2011, Basic terminated the revolving credit facility and completed the closing of an early tender for approximately $224.7 million of the Senior Secured Notes and delivered to the trustee amounts required to satisfy and discharge remaining obligations for the outstanding notes. Basic also incurred $3.2 million of deferred debt costs associated with the revolving credit facility entered into on February 15, 2011. Additionally, on

June 13, 2011, Basic incurred $12.4 million of deferred debt costs associated with the issuance of additional 7.75% Senior Notes due 2019.

Goodwill and Other Intangible Assets

Goodwill and other intangible assets not subject to amortization are tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. A qualitative assessment is allowed to determine if goodwill is potentially impaired. The qualitative assessment determines whether it is more likely than not that a reporting unit's fair value is less than its carrying amount. If it is more likely that not that the fair value of the reporting unit is less than the carrying amount, then the two step impairment test is performed. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. If impairment is indicated, then the fair value of the reporting unit's goodwill is determined by allocating the unit's fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination. The amount of impairment for goodwill is measured as the excess of its carrying value over its fair value. Basic completes its assessment of goodwill impairment as of December 31 each year. No impairment was recorded for the years ended December 31, 2013, 2012 and 2011.

The changes in the carrying amount of goodwill for the year ended December 31, 2013, are as follows (in thousands):

	Completion and Remedial Services	Fluid Services	Well Servicing	Contract Drilling	Total
Balance as of December 31, 2012	$ 79,047	$ 20,467	$ 6,322	$ -	$ 105,836
Goodwill additions	-	6,128	300	-	6,428
Purchase price adjustment	(1,350)	-	-	-	(1,350)
Balance as of December 31, 2013	$ 77,697	$ 26,595	$ 6,622	$ -	$ 110,914

Basic had trade names of $1.9 million as of December 31, 2013 and 2012. Trade names have an indefinite life and are tested for impairment annually.

Basic's intangible assets subject to amortization consist of customer relationships, non-compete agreements and rig engineering plans. The gross carrying amount of customer relationships subject to amortization was $87.1 million and $90.1 million as of December 31, 2013 and 2012, respectively. The gross carrying amount of non-compete agreements subject to amortization totaled approximately $13.0 million and $8.0 million at December 31, 2013 and 2012, respectively. The gross carrying amount of other intangible assets subject to amortization was $2.1 million as of December 31, 2013 and $1.1 million as of December 31, 2012, respectively. Accumulated amortization related to these intangible assets totaled approximately $26.6 million and $18.4 million at December 31, 2013 and 2012, respectively. Amortization expense for the years ended December 31, 2013, 2012 and 2011 was approximately $8.4 million, $6.9 million, and $5.5 million, respectively. Amortization expense for the next five succeeding years is estimated to be approximately $8.2 million, $8.1 million, $7.6 million, $7.5 million, and $6.1 million in 2014, 2015, 2016, 2017 and 2018, respectively. Other intangibles net of accumulated amortization allocated to reporting units as of December 31, 2013 were $56.1 million, $11.9 million, $5.8 million and $3.8 million for completion and remedial services, fluid services, well servicing, and contract drilling, respectively.

Amortizable Intangible Assets at December 31, 2013 (in thousands):	
Customer Relationships	$ 87,139
Accumulated Amortization Customer Relationships	(22,020)
Non-Compete Agreements	13,004
Accumulated Amortization Non-Compete Agreements	(4,293)
Other Intangible Assets	4,025
Accumulated Amortization Other Intangible Assets	(300)
Total Amortizable Intangible Assets	$ 77,555

Customer relationships are amortized over a 15-year life, non-compete agreements are amortized over a five-year life, rig engineering plans and developed technology are amortized over 15-year life.

Basic has identified its reporting units to be completion and remedial services, fluid services, well servicing and contract drilling.

Stock-Based Compensation

Basic has historically compensated our directors, executives and employees through the awarding of stock options and restricted stock. Basic accounted for stock option and restricted stock awards in 2011, 2012, and 2013 using a grant date fair-value based method, resulting in compensation expense for stock-based awards being recorded in our consolidated statements of income. For performance based restricted stock awards, compensation expense is recognized in the Company's financial statements based on their grant date fair value. Basic utilizes (i) the closing stock price on the date of grant to determine the fair value of vesting restricted stock awards and (ii) a Monte Carlo simulation to determine the fair value of restricted stock awards with a combination of market and service vesting criteria. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. The expected volatility utilized in the model was estimated using our historical volatility and the historical volatilities of our peer companies. The risk-free interest rate was based on the U.S. treasury rate for a term commensurate with the expected life of the grant. Stock options issued are valued on the grant date using Black-Scholes-Merton option pricing model and restricted stock issued is valued based on the fair value of Basic’s common stock at the grant date. In addition, judgment is required in estimating the amount of stock-based awards that are expected to be forfeited. Because the determination of these various assumptions is subject to significant management judgment and different assumptions could result in material differences in amounts recorded in Basic’s consolidated financial statements, management believes that accounting estimates related to the valuation of stock options are critical.

Income Taxes

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 statutory tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in the period that includes the statutory enactment date. A valuation allowance for deferred tax assets is recognized when it is more likely than not that the benefit of deferred tax assets will not be realized.

Accounts Receivable

Basic estimates its allowance for losses on accounts receivable based on historic collections and expectations for future collections. These losses historically have been within management’s expectations. Basic regularly reviews accounts for collectability. After all collection efforts are exhausted, if the balance is still determined to be uncollectable, the balance is written off. Expense related to the write off of uncollected accounts is recorded in general and administrative expense.

Concentrations of Credit Risk

Financial instruments, which potentially subject Basic to concentration of credit risk, consist primarily of temporary cash investments and trade receivables. Basic restricts investment of temporary cash investments to financial institutions with high credit standing. Basic’s customer base consists primarily of multi-national and independent oil and natural gas producers. It performs ongoing credit evaluations of its customers but generally does not require collateral on its trade receivables. Credit risk is considered by management to be limited due to the large number of customers comprising its customer base. Basic maintains an allowance for potential credit losses on its trade receivables, and such losses have been within management’s expectations.

Basic did not have any one customer which represented 10% or more of consolidated revenue for 2013, 2012 or 2011.

Asset Retirement Obligations

Basic is required to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets and capitalize an equal amount as a cost of the asset depreciating it over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each quarter to reflect the passage of time, changes in the estimated future cash flows underlying the obligation, acquisition or construction of assets, and settlements of obligations.

Environmental

Basic is subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require Basic to remove or mitigate the adverse environmental effects of disposal or release of petroleum, chemical and other substances at various sites. Environmental expenditures are expensed or capitalized depending on the future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated.

Litigation and Self-Insured Risk Reserves

Basic estimates its reserves related to litigation and self-insured risks based on the facts and circumstances specific to the litigation and self-insured claims and its past experience with similar claims. Basic maintains accruals in the consolidated balance sheets to cover self-insurance retentions (See Note 7).

Comprehensive Income (Loss)

All items that are required to be recognized under accounting rules as components of comprehensive income (loss) are to be reported in a financial statement that is displayed with the same prominence as other financial statements. Gains and losses on cash flow hedging derivatives, to the extent effective, are included in other comprehensive income (loss). For the three-year period ended December 31, 2013, Basic did not have any items of other comprehensive income (loss).

Recent Accounting Pronouncements

In December 2011, the FASB issued ASU No. 2011-11, “Balance Sheet” (“ASU 2011-11”). The standard amends and expands disclosure requirements about balance sheet offsetting and related arrangements. ASU 2011-11 became effective for Basic on January 1, 2013. The adoption of this standard did not have a material impact to Basic’s results of operations, financial position or liquidity as a result of this guidance.

In July 2012, the FASB issued ASU No. 2012-02, “Intangibles — Goodwill and Other: Testing Indefinite-Lived Intangible Assets for Impairment” (“ASU 2012-02”). ASU 2012-02 allows a qualitative assessment of whether it is more likely than not that the indefinite-lived intangible asset’s fair value is less than its carrying amount before applying the quantitative impairment test. If it is more likely than not that the fair value of an indefinite-lived intangible asset is less than its carrying amount, then the impairment test for that indefinite-lived intangible asset would be performed. ASU 2012-02 is effective for annual and interim impairment tests performed for indefinite-lived intangible assets for fiscal years beginning after September 15, 2012 and early adoption is permitted. Basic early adopted this accounting standard update and although it has changed the process Basic uses to determine if indefinite-lived intangible assets are impaired, it has not had a material impact on Basic’s consolidated financial statements.

In July 2013, the FASB issued ASU No. 2013-11, “Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exist” (“ASU2013-11”). ASU 2013-11 reduces diversity in proactive by providing guidance on the presentation of unrecognized tax benefits and will better reflect the manner in which an entity would settle at the reporting date any additional income taxes that would result from the disallowance of a tax position when net operating loss carryforwards, similar tax losses, or tax credit carryforwards exist. ASU 2013-11 becomes effective for Basic on January 1, 2014 and Basic does not believe it will have a material impact on Basic’s consolidated financial statements.

3.Acquisitions

In 2013, 2012 and 2011, Basic acquired either substantially all of the assets or all of the outstanding capital stock of each of the following businesses, each of which were accounted for using the purchase method of accounting. The following table summarizes the final values at the date of acquisition (in thousands):

	Closing Date	Total Cash Paid (net of cash acquired)
Lone Star Anchor Trucking, Inc	July 7, 2011	$ 10,102
Maverick Stimulation Company, LLC, Maverick Coil Tubing Services, LLC, Maverick Thru-Tubing, LLC, Maverick Solutions, LLC, The Maverick Companies, LLC, MCM Holdings, LLC, and MSM Leasing LLC (collectively the "Maverick Companies")	July 8, 2011	186,251
Pat's P&A, Inc.	August 1, 2011	8,974
Cryogas Services LLP	September 8, 2011	11,085
Total 2011		$ 216,412
Mayo Marrs Casing Pulling, Inc.	January 13, 2012	$ 6,644
SPA Victoria, LP	March 16, 2012	11,948
Surface Stac, Inc.	May 15, 2012	23,184
Salt Water Disposal of North Dakota LLC	December 19, 2012	43,190
Total 2012		$ 84,966
Atlas Environmental Consulting, Inc. and Atlas Oilfield Construction Company, LLC	February 19, 2013	$ 12,979
Petroleum Water Solutions, LLC	February 22, 2013	3,288
Karnes Water Management, LLC	December 31, 2013	5,200
Total 2013		$ 21,467

The operations of each of the acquisitions listed above are included in Basic's statement of operations as of each respective closing date. The acquisition of the Maverick Companies in July 2011 has been deemed significant and is discussed below in further detail. The pro forma effect of the remainder of the acquisitions completed in 2011, 2012 or 2013 are not material, either individually or when aggregated, to the reported results of operations. The provisional value used on Karnes Water Management, LLC will be finalized once the valuation of the tangible and intangible assets is complete.

The Maverick Companies

On July 8, 2011, Basic acquired all of the equity interests of Maverick Stimulation Company, LLC, Maverick Coil Tubing Services, LLC, Maverick Thru-Tubing, LLC, Maverick Solutions, LLC, The Maverick Companies, LLC, MCM Holdings, LLC, and MSM Leasing LLC (collectively the "Maverick Companies"). The results of the Maverick Companies' operations have been included in the financial statements since that date. The amount of revenue included in the consolidated income statement in 2012 and 2011 was $130.8 million and $62.4 million, respectively. The aggregate purchase price was approximately $186.3 million in cash. This acquisition allowed us to expand our stimulation, coiled tubing, and thru tubing business in Colorado, New Mexico, Utah, and Oklahoma. This acquisition also allowed us to enter the water treatment business. The Maverick Companies operate in Basic's completion and remedial segment. The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition for the Maverick Companies (in thousands):

Current Assets	$ 17,112
Property and Equipment	92,856
Other Intangible Assets (1)	29,400
Goodwill (2)	60,381
Other Non-Current Assets	464
Total Assets Acquired	$ 200,213
Current Liabilities	$ 11,824
Deferred Income Taxes	-
Total Liabilities Assumed	$ 11,824
Net Assets Acquired	$ 188,389

(1) Other intangible assets consists of customer relationship of $25.3 million, amortizable over 15 years, non-compete agreements of $3.6 million, amortizable over five years, intellectual property of $380,000, amortizable over 15 years, and trade name of $170,000 with an indefinite life.
(2) Goodwill is primarily attributable to operational and cost synergies expected to be realized from the acquisition by integrating Maverick's equipment and assembled workforce. All of the goodwill is expected to be deductible for tax purposes.

4.Property and Equipment

Property and equipment consists of the following (in thousands):

	December 31, 2013	December 31, 2012
Land	$ 17,800	$ 16,338
Buildings and improvements	65,702	53,831
Well service units and equipment	498,846	487,785
Fluid services equipment	258,371	218,933
Brine and fresh water stations	13,496	14,101
Frac/test tanks	275,603	274,311
Pumping equipment	299,300	277,529
Construction equipment	15,677	15,657
Contract drilling equipment	104,958	105,992
Disposal facilities	143,459	119,903
Light vehicles	64,942	61,802
Rental equipment	70,738	65,047
Aircraft	-	4,151
Software	23,360	23,922
Other	16,754	19,055
	1,869,006	1,758,357
Less accumulated depreciation and amortization	940,969	814,591
Property and equipment, net	$ 928,037	$ 943,766

Basic is obligated under various capital leases for certain vehicles and equipment that expire at various dates during the next five years. The gross amount of property and equipment and related accumulated amortization recorded under capital leases and included above consists of the following (in thousands):

	December 31, 2013	December 31, 2012
Light vehicles	$ 39,970	$ 31,180
Contract drilling equipment	4,223	4,223
Well service units and equipment	1,554	1,748
Fluid services equipment	121,051	105,932
Pumping equipment	29,080	29,253
Construction equipment	1,005	974
Software	17,120	17,120
Other	70	344
	214,073	190,774
Less accumulated amortization	77,340	63,194
	$ 136,733	$ 127,580

Amortization of assets held under capital leases of approximately $31.7 million, $28.5 million and $22.0 million for the years ended December 31, 2013, 2012 and 2011, respectively, is included in depreciation and amortization expense in the consolidated statements of operations.

5.Long-Term Debt

Long-term debt consists of the following (in thousands):

	December 31, 2013	December 31, 2012
Credit Facilities:		
Revolver	$ -	$ -
7.75% Senior Notes due 2019	475,000	475,000
7.75% Senior Notes due 2022	300,000	300,000
Unamortized premium	1,459	1,683
Capital leases and other notes	111,626	106,458
	888,085	883,141
Less current portion	41,394	38,235
	$ 846,691	$ 844,906

7.75% Senior Notes due 2019

On February 15, 2011, Basic issued $275.0 million aggregate principal amount of 7.75% Senior Notes due 2019 (the "2019 Notes"). On June 13, 2011, Basic issued an additional $200.0 million aggregate principal amount of 2019 Notes, resulting in outstanding 2019 Notes with aggregate principal amount of $475.0 million. The 2019 Notes are jointly and severally, and unconditionally, guaranteed on a senior unsecured basis by all of Basic's current subsidiaries, other than three immaterial subsidiaries. The 2019 Notes and the guarantees rank (i) equally in right of payment with any of Basic's and the subsidiary guarantors' existing and future senior indebtedness, including Basic's existing 7.75% Senior Notes due 2022 and the related guarantees, and (ii) effectively junior to all existing or future liabilities of Basic's subsidiaries that do not guarantee the 2019 Notes and to Basic and the subsidiary guarantors' existing or future secured indebtedness to the extent of the value of the collateral therefor.

The 2019 Notes and the guarantees were offered and sold in private transactions in accordance with Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act").

The purchase price for the $275.0 million of 2019 Notes issued on February 15, 2011 was 100.000% of their principal amount, and the purchase price for the $200.0 million of 2019 Notes issued on June 13, 2011 was 101.000%, plus accrued interest from February 15, 2011. Basic received net proceeds from the issuance of the 2019 Notes of approximately $464.6 million after premiums and offering expenses. Basic used a portion of the net proceeds from the February 2011 offering to fund Basic's tender offer and consent solicitation for Basic's 11.625% Senior Secured Notes and to redeem any of the Senior Secured Notes not purchased in the tender offer. Basic used the net proceeds from the June 2011 offering to fund the $186.3 million purchase price for the Maverick Companies acquisition completed in July 2011 and for general corporate purposes.

The 2019 Notes were issued pursuant to an indenture dated as of February 15, 2011 (the "2019 Notes Indenture"), by and among Basic, the guarantors party thereto and Wells Fargo Bank, N.A., as trustee. Interest on the 2019 Notes accrues from and including February 15, 2011 at a rate of 7.75% per year. Interest on the 2019 Notes is payable semi-annually in arrears on February 15 and August 15 of each year. The 2019 Notes mature on February 15, 2019.

The 2019 Notes Indenture contains covenants that, among other things, limit Basic's ability and the ability of certain of its subsidiaries to:

- incur additional indebtedness;
- pay dividends or repurchase or redeem capital stock;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates;
- limit dividends or other payments by Basic's restricted subsidiaries to Basic; and
- sell assets or consolidate or merge with or into other companies.

These and other covenants that are contained in the 2019 Notes Indenture are subject to important exceptions and qualifications set forth in the 2019 Notes Indenture. At December 31, 2013, Basic was in compliance with the restrictive covenants under the 2019 Notes Indenture.

Basic may, at its option, redeem all or part of the 2019 Notes, at any time on or after February 15, 2015, at a redemption price equal to 100% of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest to the date of redemption.

At any time before February 15, 2014, Basic, at its option, may redeem up to 35% of the aggregate principal amount of the 2019 Notes issued under the 2019 Notes Indenture with the net cash proceeds of one or more qualified equity offerings at a redemption price of 107.750% of the principal amount of the 2019 Notes to be redeemed, plus accrued and unpaid interest to the date of redemption, as long as:

- at least 65% of the aggregate principal amount of the 2019 Notes issued under the 2019 Notes Indenture remains outstanding immediately after the occurrence of such redemption; and

- such redemption occurs within 90 days of the date of the closing of any such qualified equity offering.

In addition, at any time before February 15, 2015, Basic may redeem some or all of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes, plus an applicable premium and accrued and unpaid interest to the date of redemption.

Following a change of control, as defined in the 2019 Notes Indenture, Basic will be required to make an offer to repurchase all or a portion of the 2019 Notes at 101% of their principal amount, plus accrued and unpaid interest to the date of repurchase.

7.75% Senior Notes due 2022

On October 16, 2012, Basic issued $300.0 million aggregate principal amount of 7.75% Senior Notes due 2022 (the "2022 Notes"). The 2022 Notes are jointly and severally, and unconditionally, guaranteed on a senior unsecured basis initially by all of Basic's current subsidiaries other than three immaterial subsidiaries. The 2022 Notes and the guarantees rank (i) equally in right of payment with any of Basic’s and the subsidiary guarantors’ existing and future senior indebtedness, including Basic’s existing 2019 Notes and the related guarantees, and (ii) effectively junior to all existing or future liabilities of Basic’s subsidiaries that do not guarantee the 2022 Notes and to Basic’s and the subsidiary guarantors’ existing or future secured indebtedness to the extent of the value of the collateral therefor.

The 2022 Notes and the guarantees were offered and sold in private transactions in accordance with Rule 144A and Regulation S under the Securities Act. Basic received net proceeds from the issuance of the 2022 Notes of approximately $293.3 million after discounts and offering expenses. Basic used a portion of the net proceeds from the offering to fund Basic’s pending tender offer and consent solicitation for Basic’s 7.125% Senior Notes due 2016 (The “2016 Notes”) and to redeem any of the 2016 Notes not purchased in the tender offer. The remainder of the net proceeds were used for general corporate purposes.

The 2022 Notes and the guarantees were issued pursuant to an indenture dated as of October 16, 2012 (the “2022 Notes Indenture”), by and among Basic, the guarantors party thereto and Wells Fargo Bank, National Association, as trustee. Interest on the 2022 Notes accrues from and including October 16, 2012 at a rate of 7.75% per year. Interest on the 2022 Notes is payable semi-annually in arrears on April 15 and October 15 of each year, commencing on April 15, 2013. The 2022 Notes mature on October 15, 2022.

The 2022 Notes Indenture contains covenants that, among other things, limit Basic's ability and the ability of certain of Basic's subsidiaries to:

- incur additional indebtedness;
- pay dividends or repurchase or redeem capital stock;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates;
- limit dividends or other payments by Basic's restricted subsidiaries to Basic; and
- sell assets or consolidate or merge with or into other companies.

These and other covenants that are contained in the 2022 Notes Indenture are subject to important exceptions and qualifications set forth in the 2022 Notes Indenture. At December 31, 2013, Basic was in compliance with the restrictive covenants under the 2022 Notes Indenture.

Basic may, at its option, redeem all or part of the 2022 Notes, at any time on or after October 15, 2017, at a redemption price equal to 100% of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest to the date of redemption.

At any time before October 15, 2015, Basic, at its option, may redeem up to 35% of the aggregate principal amount of the 2022 Notes issued under the 2022 Notes Indenture with the net cash proceeds of one or more qualified equity offerings at a redemption price of 107.750% of the principal amount of the 2022 Notes to be redeemed, plus accrued and unpaid interest to the date of redemption, as long as:

- at least 65% of the aggregate principal amount of the 2022 Notes issued under the 2022 Notes Indenture remains outstanding immediately after the occurrence of such redemption; and

" such redemption occurs within 90 days of the date of the closing of any such qualified equity offering.

In addition, at any time before October 15, 2017, Basic may redeem some or all of the 2022 Notes at a redemption price equal to 100% of the principal amount of the 2022 Notes, plus an applicable premium and accrued and unpaid interest to the date of redemption.

Following a change of control, as defined in the 2022 Notes Indenture, Basic will be required to make an offer to repurchase all or a portion of the 2022 Notes at 101% of their principal amount, plus accrued and unpaid interest to the date of repurchase.

Revolving Credit Facility

On February 15, 2011, in connection with the initial offering of 2019 Notes, Basic terminated its previous $30.0 million secured revolving credit facility with Capital One, National Association, and entered into a credit agreement (the “Credit Agreement”) providing for a new $165.0 million Revolving Credit Facility with Merrill Lynch, Pierce, Fenner & Smith Incorporated and Capital One, National Association, as joint lead arrangers and joint book managers, the lenders party thereto and Bank of America, N.A., as administrative agent. The Credit Agreement includes an accordion feature whereby the total credit available to Basic can be increased by up to $100.0 million under certain circumstances, subject to additional lender commitments. The obligations under the Credit Agreement are guaranteed on a joint and several basis by each of Basic’s current subsidiaries, other than three immaterial subsidiaries, and are secured by substantially all of Basic and its subsidiary guarantors’ assets as collateral under a related Security Agreement (the “Security Agreement”). As of December 31, 2013, the non-guarantor subsidiaries held no assets and performed no operations. On July 15, 2011, Basic exercised the accordion feature and amended the Credit Agreement to increase Basic’s total credit available from $165.0 million to $225.0 million. On April 5, 2012, Basic amended the Credit Agreement to increase the aggregate amount of commitments thereunder to $250.0 million. On October 1, 2012, Basic further amended the Credit Agreement to permit the transactions contemplated by the offering of 2022 Notes and tender offer and redemption of 2016 Notes. On August 29, 2013, Basic further amended the Credit Agreement to amend the required leverage ratios.

Borrowings under the Credit Agreement mature on January 15, 2016, and Basic has the ability at any time to prepay the Credit Agreement without premium or penalty. At Basic’s option, advances under the Credit Agreement may be comprised of (i) alternate base rate loans, at a variable base interest rate plus a margin ranging from 1.50% to 2.50% based on Basic’s leverage ratio or (ii) Eurodollar loans, at a variable base interest rate plus a margin ranging from 2.50% to 3.50% based on Basic’s leverage ratio. Basic will pay a commitment fee equal to 0.50% on the daily unused amount of the commitments under the Credit Agreement.

The Credit Agreement contains various covenants that, subject to agreed upon exceptions, limit Basic's ability and the ability of certain of its subsidiaries to:

•incur indebtedness;

•grant liens;

•enter into sale and leaseback transactions;

•make loans, capital expenditures, acquisitions and investments;

•change the nature of business;

•acquire or sell assets or consolidate or merge with or into other companies;

•declare or pay dividends;

•enter into transactions with affiliates;

•enter into burdensome agreements;

•prepay, redeem or modify or terminate other indebtedness;

•change accounting policies and reporting practices; and

•amend organizational documents.

The Credit Agreement also contains covenants that, among other things, limit the amount of capital contributions Basic may make and require Basic to maintain specified ratios or conditions as follows:

· a minimum consolidated interest coverage ratio of not less than 2.50 to 1.00;

· a maximum consolidated leverage ratio as follows:

o for the four fiscal quarters ending September 30, 2013 and December 31, 2013, a maximum consolidated leverage ratio not to exceed 4.50 to 1.00;

o for the four fiscal quarters ending March 31, 2014 and June 30, 2014, a maximum consolidated leverage ratio not to exceed 4.25 to 1.00; and

o for the four fiscal quarters ending September 30, 2014 and each fiscal quarter thereafter, a maximum consolidated leverage ratio not to exceed 4.00 to 1.00; and

· a maximum consolidated senior secured leverage ratio as follows:

o for the four fiscal quarters ending September 30, 2013 through June 30, 2014, a maximum consolidated senior secured leverage ratio not to exceed 1.75 to 1.00; and o for the four fiscal quarters ending September 30, 2014 and each fiscal quarter thereafter, a maximum consolidated senior secured leverage ratio not to exceed 2.00 to 1.00.

If an event of default occurs under the Credit Agreement, then the lenders may (i) terminate their commitments under the Credit Agreement, (ii) declare any outstanding loans under the Credit Agreement to be immediately due and payable after applicable grace periods and (iii) foreclose on the collateral secured by the Security Agreement.

Basic had no borrowings and $37.7 million of letters of credit outstanding under the Credit Agreement as of December 31, 2013, giving Basic $212.3 million of available borrowing capacity. At December 31, 2013, Basic was in compliance with its covenants under the Credit Agreement.

Other Debt

Basic has a variety of other capital leases and notes payable outstanding that are generally customary in its business. None of these debt instruments are individually material. Basic's leases with Banc of America Leasing & Capital, LLC require Basic to maintain a minimum debt service coverage ratio of 1.05 to 1.00. At December 31, 2013, Basic was in compliance with this covenant.

As of December 31, 2013 the aggregate maturities of debt, including capital leases, for the next five years and thereafter are as follows (in thousands):

	Debt	Capital Leases
2014	$ -	$ 41,394
2015	-	32,295
2016	-	24,658
2017	-	11,176
2018	-	1,987
Thereafter	775,000	115
	$ 775,000	$ 111,625

Basic's interest expense consisted of the following (in thousands):

	Years ended December 31,		
	2013	2012	2011
Cash payments for interest	$ 62,609	$ 56,522	$ 47,077
Commitment and other fees paid	1,905	1,658	915
Amortization of debt issuance costs and discount on senior secured notes	2,878	2,646	2,495
Change in accrued interest	129	1,559	3,347
Capitalized interest	(354)	(353)	-
Other	40	406	52
Total Interest Expense	$ 67,207	$ 62,438	$ 53,886

Losses on Extinguishment of Debt

In October 2012, upon the retirement of the 2016 Notes, Basic paid a premium of $6.1 million to the holders of the 2016 Notes for the early termination of the notes. In February 2011, upon the retirement of the 11.625% Senior Secured Notes and the termination of Basic's $30.0 million revolving credit facility, Basic wrote off unamortized debt issuance costs of approximately $3.9 million and unamortized discount of $9.2 million. Basic also paid a premium of $36.2 million to the holders of the 11.625% Senior Secured Notes for the early termination of the notes.

6.Income Taxes

Income tax expense (benefit) consists of the following (in thousands):

Years ended December 31,

	2013	2012 (See Note 1)	2011 (See Note 1)
Current:			
Federal	$ -	$ -	$ (57)
State	435	(813)	1,150
Total	435	(813)	1,093
Deferred:			
Federal	(18,873)	11,258	27,046
State	(1,287)	(182)	2,755
Total	(20,160)	11,076	29,801
Total income tax expense (benefit)	$ (19,725)	$ 10,263	$ 30,894

Basic paid no federal income taxes during 2013 and paid federal income taxes of $601,000 during 2012. Basic paid no federal income taxes during 2011.

Reconciliation between the amount determined by applying the federal statutory rate of 35% to income from continuing operations with the provision for income taxes is as follows (in thousands):

	Years ended December 31,		
	2013	2012 (See Note 1)	2011 (See Note 1)
Statutory federal income tax	$ (19,479)	$ 10,459	$ 26,739
Meals and entertainment	660	672	630
State taxes, net of federal benefit	(966)	(758)	3,504
Changes in estimates and other	60	(110)	21
	$ (19,725)	$ 10,263	$ 30,894

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are as follows (in thousands):

	December 31,	
	2013	2012
Deferred tax assets:		(See Note 1)
Receivables allowance	$ 1,361	$ 1,026
Inventory	273	234
Asset retirement obligation	573	530
Accrued liabilities	12,117	10,177
Operating loss carryforward	48,679	21,254
Goodwill and intangibles	1,768	5,119
Deferred compensation	10,693	10,939
Total deferred tax assets	$ 75,464	$ 49,279
Deferred tax liabilities:		
Property and equipment	(206,562)	(199,765)
Prepaid expenses	(1,772)	(2,414)
Total deferred tax liabilities	$ (208,334)	$ (202,179)
Net deferred tax liability	$ (132,870)	$ (152,900)
Recognized as:		
Deferred tax assets - current	31,436	32,201
Deferred tax liabilities - non-current	(164,306)	(185,101)
Net deferred tax liabilities	$ (132,870)	$ (152,900)

Basic provides a valuation allowance when it is more likely than not that some portion of the deferred tax assets will not be realized. There was no valuation allowance necessary as of December 31, 2013 or 2012.

Interest is recorded in interest expense and penalties are recorded in income tax expense. Basic had no interest or penalties related to an uncertain tax positions during 2013. Basic files federal income tax returns and state income tax returns in Texas and other state tax jurisdictions. In general, the Company's federal tax returns for fiscal years after 2005 currently remain subject to examination by appropriate taxing authorities. The Company's 2011 federal income tax return is under examination at this time.

As of December 31, 2013, Basic had approximately $121.3 million of net operating loss carryforwards ("NOL") for income tax purposes, which begin to expire in 2030.

7.Commitments and Contingencies

Environmental

Basic is subject to various federal, state and local environmental laws and regulations that establish standards and requirements for protection of the environment. Basic cannot predict the future impact of such standards and requirements which are subject to change and can have retroactive effectiveness. Basic continues to monitor the status of these laws and regulations. Management believes that the likelihood of new environmental regulations resulting in a material adverse impact to Basic's financial position, liquidity, capital resources or future results of operations is unlikely.

Currently, Basic has not been fined, cited or notified of any environmental violations that would have a material adverse effect upon its financial position, liquidity or capital resources other than the situation noted below. However, management does recognize that by the very nature of its business, material costs could be incurred in the near term to maintain compliance. The amount of such future expenditures is not determinable due to several factors, including the unknown magnitude of possible regulation or liabilities, the unknown timing and extent of the corrective actions which may be required, the determination of Basic's liability in proportion to other responsible parties and the extent to which such expenditures are recoverable from insurance or indemnification.

During April 2011, Basic received notice from the Travis County District Attorney of a pending investigation of a case referred by Texas Parks & Wildlife and the Texas Environmental Enforcement Task Force. The potential matter related to a land farm owned by Basic located in Jefferson County, Texas. The matter was tried in Travis County, Texas, and Basic and an indemnified third party received a judgment in October 2012. Although Basic was not directly held responsible for any fines or penalties, Basic paid approximately $1.4 million to an indemnified third party in connection with the judgment.

Litigation

From time to time, Basic is a party to litigation or other legal proceedings that Basic considers to be a part of the ordinary course of business. Basic is not currently involved in any legal proceedings that it considers probable or reasonably possible, individually or in the aggregate, to result in a material adverse effect on its financial condition, results of operations or liquidity.

In July 2013, Basic paid $8.0 million related to a settlement of a case stemming from an accident that occurred in 2008.

State Tax Audit

In 2011, Basic was notified by the Texas State Comptroller's office that a sales and use tax audit for the period from 2006 through 2010 would be conducted. In 2012 based on Basic's analysis, the potential liability associated with this audit ranged from $5.9 million to $7.3 million. An accrual for the estimated liability of $5.9 million was recorded in 2012 in Basic's financial statements as general and administrative expense. In 2013, a final settlement was agreed upon for $7.4 million, resulting in an additional $1.5 million of expense recorded in 2013.

Operating Leases

Basic leases certain property and equipment under non-cancelable operating leases. The term of the operating leases generally range from 12 to 60 months with varying payment dates throughout each month.

As of December 31, 2013, the future minimum lease payments under non-cancelable operating leases are as follows (in thousands):

Year ended December 31,	
2014	$ 9,130
2015	7,930
2016	5,034
2017	2,507
2018	1,710
Thereafter	8,004