STRONG PRESENCE, SOLID PATH

Annual Report 2011

BASIC ENERGY SERVICES

Extensive Footprint in Prolific Basins

Basic Energy Services focuses on the well count in the most prolific oil and gas producing regions in the country. We base our core operations in proven oil and gas markets with a footprint that covers approximately 70% of the existing oil and gas production in the U.S.

Rocky Mountains

100,000+
35% 65% 225

Well Servicing
Pumping Services
- Cementing
- Acidizing
- Fracturing

Wireline
Rental/Fishing Tools
Fluid Services
- Trucking
- Frac Tanks
- SWD Wells

Coil Tubing
Well Site Construction

Permian Basin

150,000+
80% 20% 315

Well Servicing
Contract Drilling
Pumping Services
- Cementing
- Acidizing
- Fracturing

Wireline
Rental/Fishing Tools
Fluid Services
- Trucking
- Frac Tanks
- SWD Wells

Plug & Abandon

Appalachian

185,000+
15% 85% 129

Well Servicing
Snubbing Services

Mid Continent

260,000+
65% 35% 209

Well Servicing
Snubbing Services
Pumping Services
Wireline
Rental/Fishing Tools

Ark-La-Tex

70,000+
45% 55% 294

Well Servicing
Snubbing Services
Pumping Services
Rental/Fishing Tools

South Texas / Gulf Coast

45,000+
50% 50% 184

Well Servicing
Fluid Services
- Trucking
- Frac Tanks
- SWD Wells

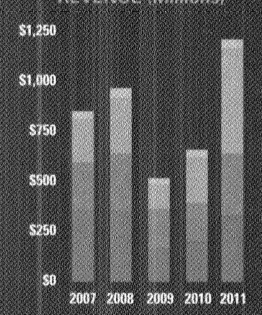
Rental/Fishing Tools
Plug & Abandon

Well Count
Recent Drilling Rig Count
Oil Well Count %
Gas Well Count %

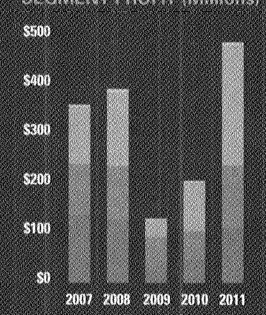
Sources: Drilling rig count is from *Land Rig Newsletter Biweekly Report.*

Financial Highlights

REVENUE (Millions)



SEGMENT PROFIT (Millions)



Contract Drilling
Completion & Remedial Services
Fluid Services
Well Servicing

EPS (Per Diluted Share)

ADJUSTED EBITDA* (Millions)

* Net income before interest, taxes, depreciation and amortization.

About Basic

With a strong presence in the country's most prolific oil and gas producing regions, Basic Energy Services provides a range of services to help America's oil and gas producers keep more than 900,000 existing wells in production throughout their lifecycle. From the initial drilling of the well to ongoing maintenance to plugging and abandonment, Basic delivers performance-driven expertise. Based in Midland, Texas, Basic employs approximately 5,600 people in Texas, Oklahoma, Louisiana, New Mexico, Kansas, Arkansas, the Rocky Mountain States and the Appalachian region. Since its founding in 1992, Basic has followed a solid path to become one of the largest well servicing companies in the United States. Our common stock is listed on the New York Stock Exchange under the symbol BAS.

Basic History of Growth

Note: Adjusted EBITDA is the non-GAAP financial measure of earnings (net income) before interest, taxes, depreciation and amortization, gain or loss on early extinguishment of debt, gain or loss on disposal of assets, goodwill impairment and gain on bargain purchase price.

1997
- Rev: $26,134
- Adj. EBITDA: $3,357
- Service Lines: Well Servicing & Fluid Services

1998
- Rev: $45,319
- Adj. EBITDA: $4,225

1999
- Rev: $37,331
- Adj. EBITDA: $2,370

2000
- Rev: $56,466
- Adj. EBITDA: $9,669
- Major Expansion: Mid Continent Market

2001
- Rev: $99,709
- Adj. EBITDA: $25,944

2002
- Rev: $108,751
- Adj. EBITDA: $16,767

2003
- Rev: $180,899
- Adj. EBITDA: $35,353
- Major Expansion: Pumping Services, Gulf Coast Market, Rocky Mountain Market

2004
- Rev: $311,502
- Adj. EBITDA: $62,156
- Major Expansion: Underbalanced Drilling

2005
- Rev: $459,752
- Adj. EBITDA: $121,718

2006
- Rev: $730,148
- Adj. EBITDA: $231,163
- Major Expansion: Rental/Fishing Tools

2007
- Rev: $877,173
- Adj. EBITDA: $258,683
- Major Expansion: Contract Drilling, Pumping Services

2008
- Rev: $1,004,942
- Adj. EBITDA: $277,207

2009
- Rev: $526,627
- Adj. EBITDA: $33,984

2010
- Rev: $728,239
- Adj. EBITDA: $114,097
- Major Expansion: Snubbing Services, Appalachian Market

2011
- Rev: $1,243,255
- Adj. EBITDA: $335,404
- Major Expansion: Coil Tubing, Nitrogen Service

($ In Thousands)

Letter to Our Shareholders

2011 was a significant year for Basic Energy Services. Despite weak demand in our gas-driven markets, we achieved record levels of revenue and EBITDA by capitalizing on our well-established positions in the major oil and liquids producing markets within our footprint. And we expanded our coverage and the range of services we provide with several acquisitions, which augment the internal growth initiatives available to us in most of our markets.

In addition to the investments in additional capacity, we continued to redeploy equipment from dry gas areas to the more active areas within our footprint, and increased revenue derived from our oil and liquids markets to more than 70% compared to an estimated 50% in 2008. Our market-leading presence in the Permian Basin in particular, where approximately 40% of our revenue is generated, allowed us to expand each of our service lines as expenditures for drilling and production services on the part of E&P companies more than doubled over the course of the year.

During the year, we invested $104 million in capital expenditures to grow our business in the Permian Basin. We substantially increased our drilling rig fleet in the Wolfberry play in the region with the purchase of three 'Super Single' class 1,000 hp rigs during the first quarter and two 1,200 hp diesel electric rigs in December. We also grew our pumping horsepower by 23% with the delivery of our 25,000 hhp frac spread, which was deployed on Wolfberry frac programs in early spring. In addition, we added 90 fluid service trucks and 661 frac tanks to our fleet during the year, with the majority of that expansion building our presence in the Permian Basin. And finally, we increased our active well servicing rig fleet by 24 rigs as we redeployed and reactivated rigs within that market.

Expanding Our Services, Enhancing Our Growth

We completed two important acquisitions during 2011 that support our strategy of broadening our local presence. The purchase of the Maverick Companies, the largest acquisition we have completed to date, significantly expanded our pumping capability in the Rocky Mountain region and added coil tubing as a new growth platform. Maverick is a great example of the type of acquisition that we believe helps build value for our shareholders.

100% increase in drilling rig fleet size due to the addition of two new 1,200 hp diesel electric rigs and three 'Super Single' class 1,000 hp rigs

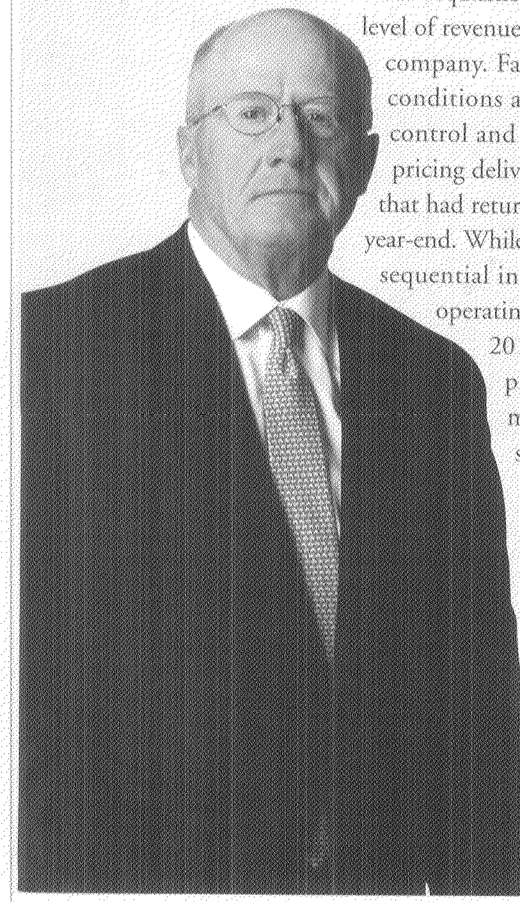
Maverick's experienced management and well-trained field personnel combined with its high quality, late-model equipment have developed the company's reputation as a first-class service provider in markets where, for the most part, we did not compete. In addition, we believe Maverick's coil tubing fleet and expertise provide an excellent foundation to rapidly build upon in several markets where we already have a substantial presence in other services.

The purchase of Lone Star Anchor Trucking is an example of the smaller kind of acquisitions that we historically have built the company on. Located in the busy Wolfberry play in the Permian Basin, Lone Star Anchor enhances our capability at a local level and added 33 fluid service trucks and two salt-water disposal wells to one of our established operations. Those additional disposal facilities will play an important role in the continued expansion of our fluid services segment as the Wolfberry play drives increased drilling and frac activity in that section of the Permian Basin.

We were particularly pleased with the performance of our well servicing segment, which generated a utilization rate of 70% for the year.

Strong Performance Across All Segments

Strong demand across our business segments and the contribution of our acquisitions resulted in a record level of revenue and EBITDA for the company. Favorable operating conditions along with good cost control and modestly improved pricing delivered an EBITDA margin that had returned to 2008 levels by year-end. While each segment generated sequential increases in revenue and operating margins throughout 2011, we were particularly pleased with the performance of our well servicing segment, which generated a utilization rate of 70% for the year. This indicates strong demand for our production support services as well as our drilling related services.



Internal Growth

The year saw Basic Energy Services making a number of positive changes internally. To meet the increased demand for our services, we hired over a thousand new employees, taking our staff level from 4,500 in 2010 to 5,600 by year-end. We're supporting that growth in our employee base with substantial investments in safety and training focused on eliminating work place accidents and injuries and improving retention. In addition, we introduced several efficiency initiatives, including updating our GPS system and streamlining our invoicing process to save time, reduce paperwork and provide a more efficient service for our customers.

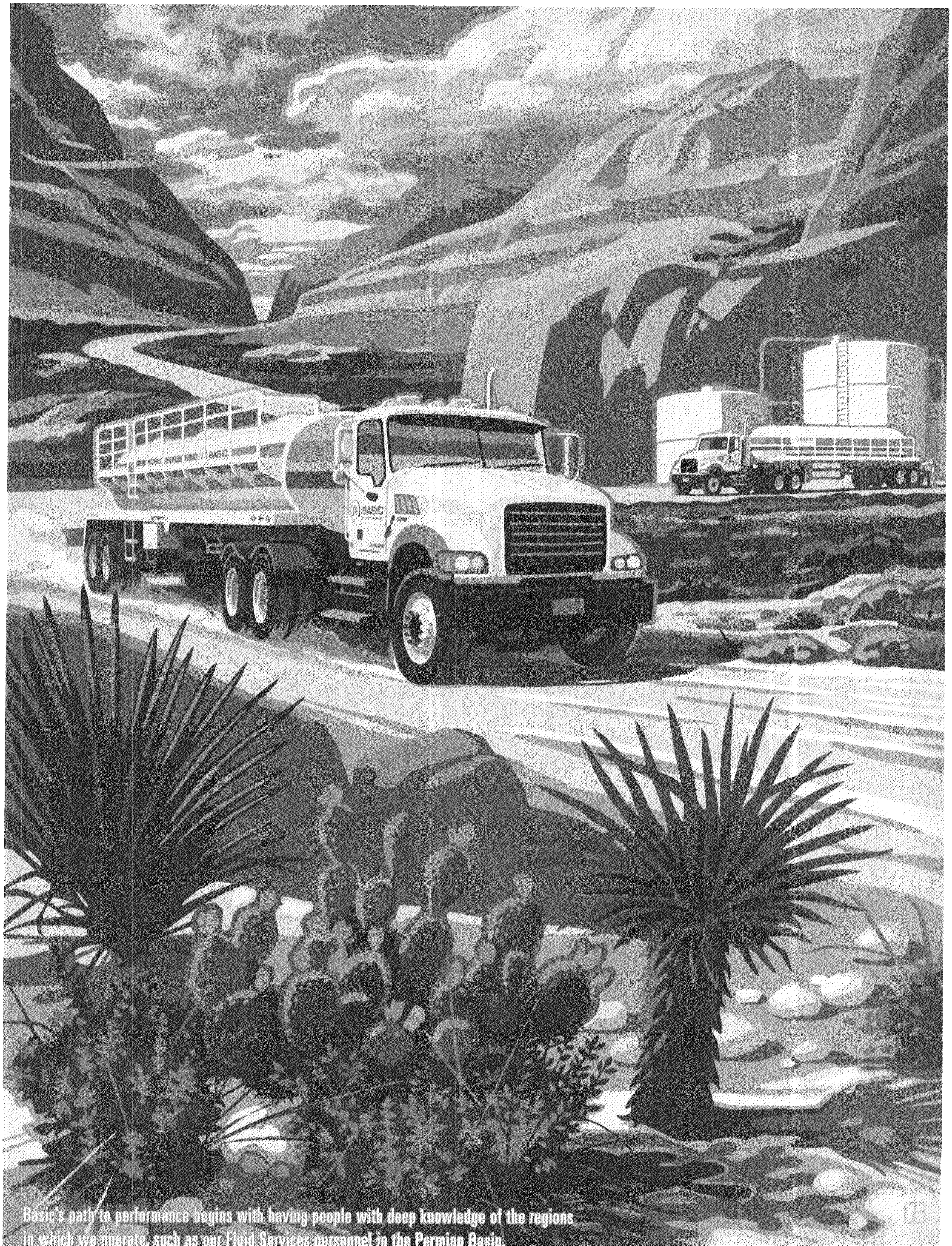
Moving Forward

Our outlook for 2012 is positive. While we don't expect much improvement in gas related activity, oil prices above $80 per barrel should drive increased expenditures for drilling and completing new wells and aggressive maintenance and workover programs to optimize production from existing wells. We are evaluating a growing list of acquisition opportunities along with steady requests from our field management for more equipment and capabilities with which to serve our local markets. We will use our strong cash flow and liquidity to take advantage of the best of those opportunities to grow our business and build shareholder value in 2012.

On a personal note, I would like to thank our board of directors, employees, customers, suppliers and shareholders who have enabled Basic to grow ever stronger through the years, strategically increasing our footprint, our services and our opportunities.

Thank you for your interest in our company.

Kenneth V. Huseman
Chief Executive Officer and President



Basic's path to performance begins with having people with deep knowledge of the regions in which we operate, such as our Fluid Services personnel in the Permian Basin.

Charting a Course to Success

Since inception, Basic Energy Services has continued to steadily grow in geographic footprint, assets and revenues.

Today Basic supports six geomarkets, conducting operations in the Texas Gulf Coast region, the Ark-La-Tex region, the Permian Basin of West Texas, the Mid Continent, the Appalachian region and the Rocky Mountains.

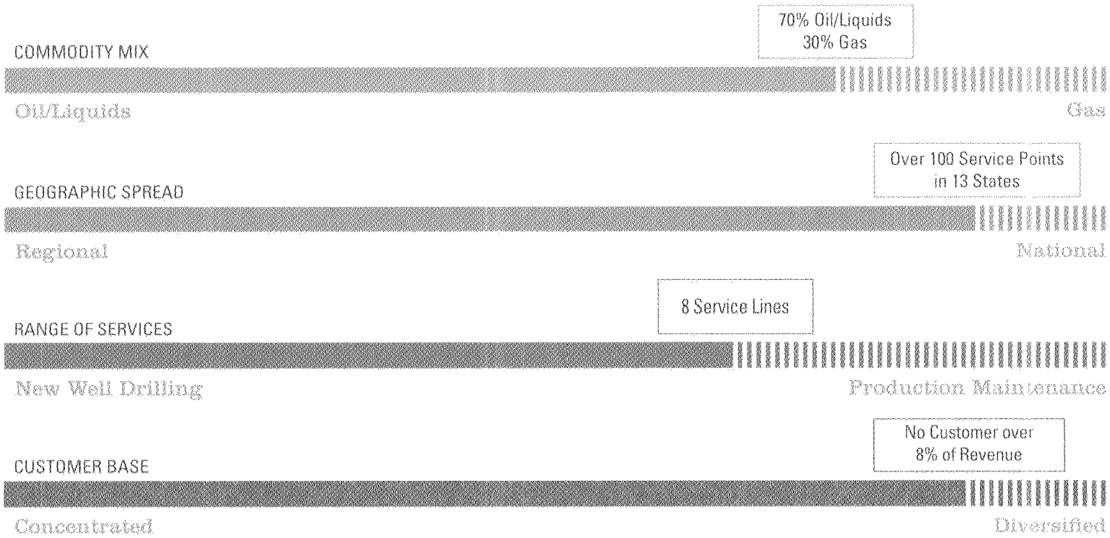
More importantly Basic enjoys a leading position in the Permian Basin – the country's most prolific region for oil and gas production. Basic's activity continues to grow in this significant oil producing province, which contains an estimated 30 Bbbl of remaining oil in place. Our growing position in the Permian Basin was the primary driver for our outstanding performance in 2011, with total revenues reaching a record $1.2 billion.

A Diversified Customer Base

Basic has a broad, diversified customer base comprising over 2,000 active customers, with no one customer accounting for more than 8% of our revenues. Our infrastructure allows us to effectively meet the needs of well-capitalized, publicly traded customers. With an asset mix of services in the oil and liquids rich market for every phase of the well lifecycle, Basic's expertise in providing services critical to the life of the field are always in demand.

Capitalizing on Our Position

With over 800,000 wells in our footprint, Basic is focused on the most prolific oil and gas producing regions in the country. Our geographic reach covers approximately 70% of existing oil and gas production in the U.S. Furthermore our comprehensive range of services is required for both unconventional production and for optimizing activity in conventional wells in these regions.

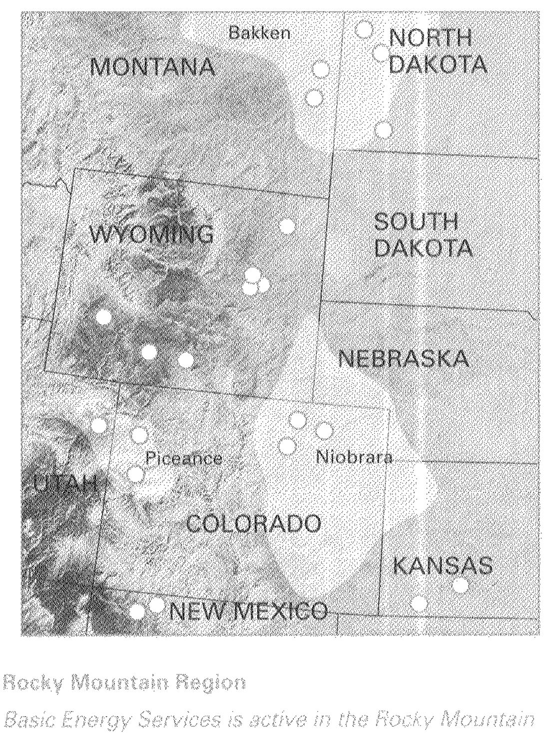


Our core operations are located in the Permian Basin, a vital energy region noted for its rich petroleum and natural gas deposits within a 150-mile radius of Midland, Texas, where Basic's headquarters are situated. More than 40% of our company's revenues come from the Permian Basin, which produces 17% of the nation's crude oil and two-thirds of Texas' crude oil. The application of improved drilling techniques and technology is helping investments go further in the region than previously possible. Producers are increasing output by using advanced drilling and completions techniques in established fields to unlock more resources.

Driving Performance the Basic Way

At Basic our range of services enables us to provide customers with the best servicing solutions regardless of the challenge, complexity or phase in the well lifecycle. Local leadership and deep knowledge of the areas in which we operate drive our performance and growth. With operations managed locally by people who have worked and lived in their region for years, we offer services that range from breaking ground at the site to drilling, production and workovers as well as plugging and abandonment. We support these regions with our national infrastructure, our strong balance sheet, our financial management systems and our comprehensive training and safety programs.

In 2011 Basic took advantage of its footprint to reposition equipment from gas markets to oil markets where activity was much greater. We also spent over $275 million in expanding our capabilities. All of Basic's service segments posted double-digit increases in revenues in 2011 due to increased demand for our expertise.



Rocky Mountain Region

Basic Energy Services is active in the Rocky Mountain region, an important area that holds some of the largest shale oil deposits in the world.

Completion and Remedial Services

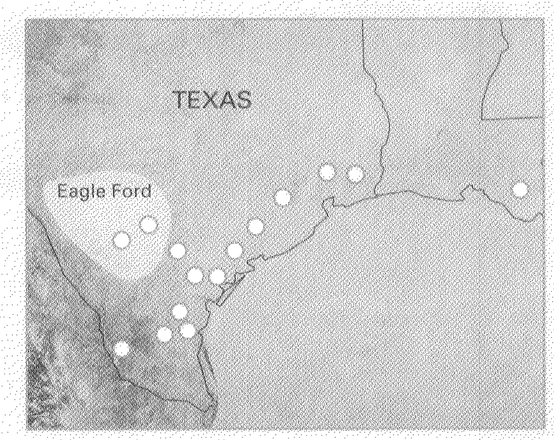
Basic operates a broad array of equipment used in cementing and drilling throughout the life of the well to optimize production. We offer comprehensive and reliable services that focus on the completion of newly drilled wells or re-entries and maintenance or remedial services to existing wellbores. Basic maintains a fleet of over 220 pressure pumping units and supports overall production with services that include rental and fishing tools, cased hole wireline services, tubing testing, rig-assisted snubbing and under-balanced drilling. In 2011 we added 60,000 hhp from the Maverick acquisition and our pumping horsepower grew 90%. Completion and Remedial Services provided the largest growth in revenue again this year with Pumping Services accounting for much of that success.

Fluid Services

Basic's Fluid Services segment provides oilfield fluid supply, transportation and storage services using a fleet of 890 fluid services trucks supported by portable storage tanks, water wells, disposal facilities and related equipment. From over 40 service points, we provide efficient and reliable dispatching via a fleet equipped with state-of-the-art global positioning systems. During the year, we added 90 fluid service trucks and 661 frac tanks. This segment posted significant gains in 2011 due to continued activity in the Permian Basin, Bakken Shale and Eagle Ford play.

Well Servicing

Leveraging a fleet of 417 mobile well servicing rigs, Basic's Well Servicing segment provides a wide range of services to improve production throughout the life of the well. From well completion, well bore maintenance and workover procedures to plugging and abandonment, we provide critical services that sustain and optimize production. We have the right equipment to handle any

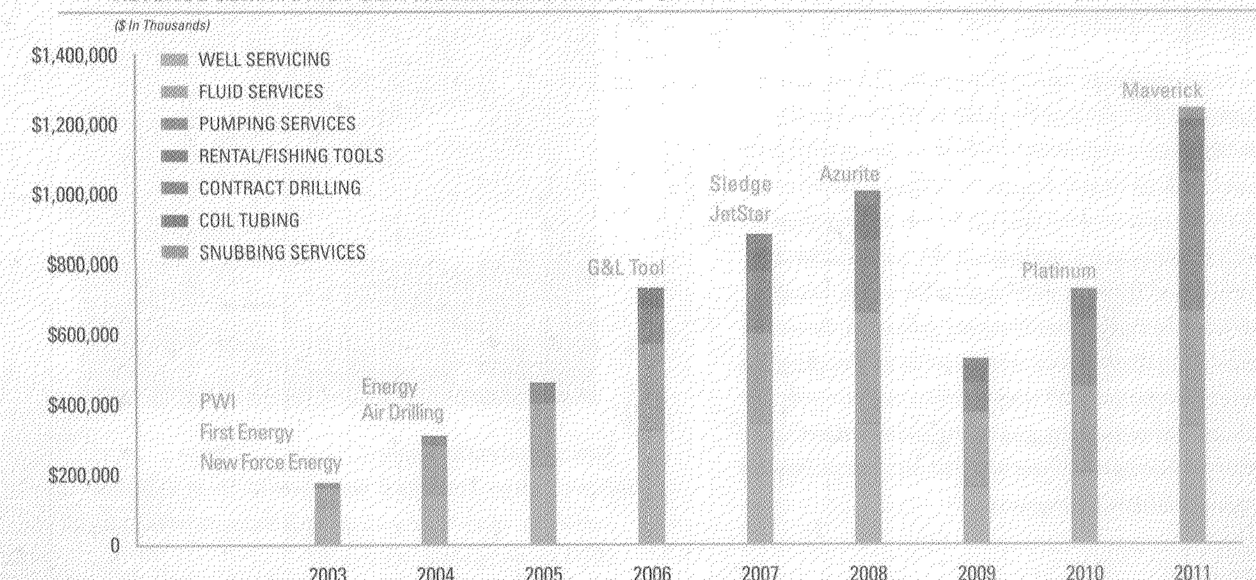


Gulf Coast Region

Basic's main focus in the Gulf Coast region is Fluid Services and Well Servicing. Included in our Gulf Coast footprint is the Eagle Ford region, one of the most significant shale reservoirs in the U.S.

REVENUE SUMMARY BY SERVICE WITH MAJOR ACQUISITIONS HIGHLIGHTED

($ In Thousands)



Our path to growth takes Basic to key areas such as Minden, Louisiana in the Ark-La-Tex region where our well servicing crews provide solid performance in the field.

Pumping horsepower grew by 90% in 2011.

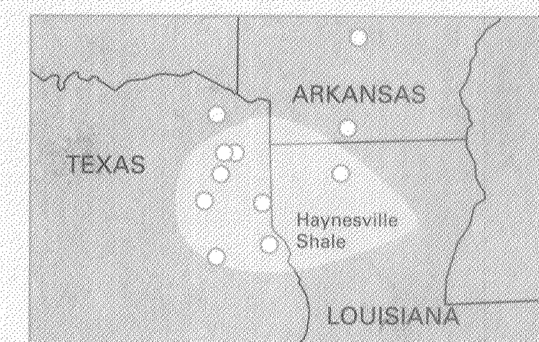
job for virtually any well within our footprint. During 2011 robust demand in our oil and liquids driven markets resulted in high utilization of these services.

Contract Drilling

Basic leverages its fleet of well-equipped drilling rigs to perform the vital function of drilling the initial wellbore. We focus on development drilling programs that are active throughout the cycle with two new diesel electric rigs rated to 16,000 ft, three 'Super Single' rigs rated to 13,000 ft, six rigs rated to 8,500 ft, two 24-hour workover rigs rated to 20,000 ft and one pre-set surface rig rated to 5,000 ft. In 2011 we doubled both our fleet size and its capability. Our strength was augmented with the addition of the three 'Super Single' class 1,000 hp rigs and a smaller rig designed for casing pre-sets. With customers pursuing aggressive drilling programs in the Permian Basin, this segment experienced strong demand through the year.

Growing According to Strategy

In 2011 Basic made four acquisitions that increased our services and strength. The acquisition of Maverick Companies, the largest purchase Basic has made to date, enabled us to build our service capabilities within our footprint in the Rocky Mountain market. Maverick provides stimulation, coil tubing and thru-tubing services from operating bases in Ft. Morgan, Grand Junction and Trinidad, Colorado; Farmington, New Mexico; Vernal, Utah; and Bartlesville, Oklahoma. As of the date of the acquisition, Maverick employed more than 180 people and operated approximately 60,000 horsepower in its stimulation segment and seven coil tubing spreads. Maverick's experienced management and well-trained field personnel combined with its high quality, late-model equipment have developed the company's reputation as a first-class service provider in markets where, for the most part, we did not compete. We look forward to providing the Maverick management team the resources necessary to continue building service capabilities within our footprint in the Rocky Mountain market.



Ark-La-Tex Region

The Ark-La-Tex region extends from northwestern Louisiana to southwestern Arkansas and eastern Texas. Home to the Haynesville shale play, Basic operates its Fluid Services, Pumping Services and Well Servicing in this vital area.

Lone Star Anchor

As a result of the Lone Star Anchor Trucks acquisition, Basic added 33 trucks to its fluid service truck count. The purchase also includes two salt-water disposal wells. Those additional disposal wells have been permitted, not completed. Those additional disposal facilities will play an important role in the continued expansion of our fluid services segment as the Wolfberry play drives increased drilling and frac activity in that section of the Permian Basin.

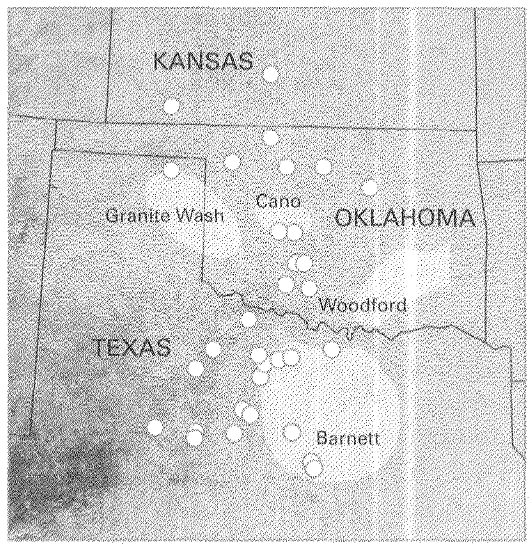
Pat's P&A

We also closed the purchase of the assets of Pat's P&A, Inc., a company based in Corpus Christi, Texas, focused on providing plugging and abandonment services primarily in the South Texas market. The Pat's acquisition adds five plugging and abandonment (P&A) rigs and related equipment to our South Texas well servicing rig fleet. The company offers zone abandoning by setting a bridge plug or squeezing with cement, setting balanced cement plugs, cutting and removing tubing and/or casing, and surface plugs setting services. It also provides well servicing, coil tubing, electric wireline and casing jacks, as well as the sale of equipment and salvage, such as used casing, tubing packers, and wellheads. The Pat's organization and fleet provides a platform to build a comprehensive P&A service in our South Texas operations similar to our P&A business in the Permian Basin, where we have a leading market position with 17 rigs dedicated to full service P&A activity.

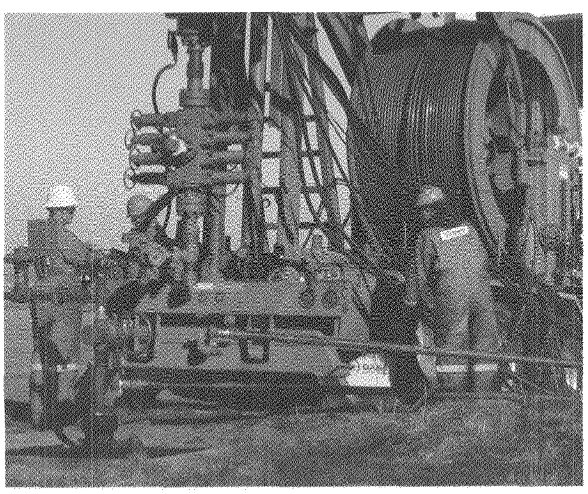
CryoGas Services

Basic's acquisition of CryoGas Services based in Duncan, Oklahoma, added five nitrogen pumping units and two nitrogen transports while significantly expanding our current nitrogen pumping capability within our Completion and Remedial Services segment.

As we move forward, acquisitions will continue to play a key role in Basic's growth.



Mid Continent Region
In the Mid Continent region, which extends from northern Texas to Oklahoma, Basic focuses on providing Well Servicing, Fluid Services, Pumping Services and Rental/Fishing Tools to customers in this crucial area.



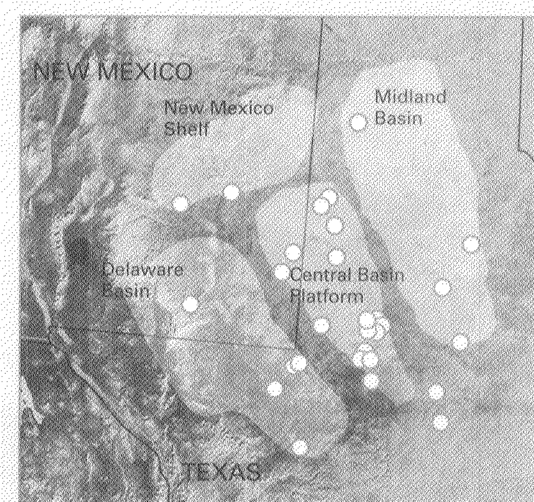
We acquired seven new coil tubing spreads and an additional 60,000 horsepower in our stimulation fleet.

Basic maintains 22 rental/ fishing tool stores located in Texas, New Mexico, Colorado and Oklahoma.

Strong Presence. Solid Path.

2011 was a year of positive execution with Basic continuing to capitalize on its strong presence in the country's most prolific oil and gas regions. Our company continued to grow with acquisitions and now offers an even wider range of services. Looking forward, we see more opportunities to grow each business line, particularly in the areas of drilling, coil tubing and snubbing. As our customers optimize existing production, well servicing services are poised to increase, and analysts project an increase in spending of 10% or more in U.S. oil and gas drilling production in most of the areas in which we work. With Basic's footprint, service range and diverse customer base, our services will remain in demand throughout the life of the well and through every cycle. From breaking ground at the site to drilling, production and workovers as well as plugging and abandonment, we are always close to the field, meeting our customers' needs quickly while creating lasting relationships in the regions in which we operate.

Basic's financial stability will enable us to continue expanding our footprint in various segments and making new value-based acquisitions that fit our growth strategy. The exceptional results we achieved in 2011 are particularly positive indicators for 2012 as we recorded our tenth consecutive sequential quarterly increase in both metrics despite the seasonal factors that typically result in a reduction in activity at year-end. Looking forward, we anticipate increases in revenue and earnings through 2012 led by expectations for strong market conditions in our footprint and the contribution from the planned growth in our fleet. As always we will continue to focus on opportunities through a disciplined approach to earn the best rate of return for our shareholders.



Permian Basin Region

In the Permian Basin region, Basic's activity continues to grow in this significant oil producing province containing an estimated 30 Bbbl of remaining mobile oil.

In the Rocky Mountain region, Basic's expanded coil tubing capabilities enable us to create an increased service path within our footprint in the market.

RECONCILIATION OF NET INCOME TO ADJUSTED EBITDA

(in millions)

	2011	2010	2009	2008	2007
Net Income (Loss)	$47	$(43)	$(254)	$68	$88
Goodwill Impairment	-	-	204	22	-
Merger-Related Income	-	-	-	(12)	-
Loss on Early Extinguishment of Debt	49	-	4	-	-
Gain on Bargain Purchase	-	(2)	-	-	-
Income Taxes	32	(25)	(88)	55	53
Net Interest Expense	52	46	32	25	25
(Gain) Loss on Disposal of Assets	1	3	3	-	-
Depreciation & Amortization	154	135	133	119	93
Adjusted EBITDA	$335	$114	$34	$277	$259

RECONCILIATION OF REPORTED DILUTED EARNINGS PER SHARE TO ADJUSTED DILUTED EARNINGS PER SHARE

	2011	2010	2009	2008	2007
Reported Diluted EPS	$1.14	$(1.10)	$(6.39)	$1.64	$2.13
Impact of Non-Cash Goodwill Impairment Charge, After Tax	-	-	4.20	0.27	-
Impact of Early Extinguishment of Debt, After Tax	0.77	-	0.06	-	-
Impact of Merger Termination Costs, After Tax	-	-	-	0.09	-
Impact of Gain on Bargain Purchase, After Tax	-	(0.04)	-	-	-
Impact of Sale of Office Complex, After Tax	(0.04)	-	-	-	-
Adjusted Diluted EPS	$1.87	$(1.14)	$(2.13)	$2.00	$2.13

Form 10-K

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, 2011

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.)*
500 W. Illinois, Suite 100 Midland, Texas	**79701**
(Address of principal executive offices)	*(Zip code)*

Registrant's telephone number, including area code:
(432) 620-5500

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

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

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 ☐ Smaller reporting company ☐
(Do not check if a 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 $711,033,841 as of June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter (based on a closing price of $31.47 per share and 22,594,021 shares held by non-affiliates).

There were 42,633,430 shares of the registrant's common stock outstanding as of February 14, 2012.

Documents incorporated by reference: Portions of the definitive 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.

Index to Form 10-K

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," "potential" and similar 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;
- the effects of future acquisitions on our business;
- changes in customer requirements in markets or industries we serve;
- competition within our industry;
- general economic and market conditions;
- our access to current or future financing arrangements;
- 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 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 and Pennsylvania. Our operations are focused on liquid 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.

We revised our business segments beginning in the first quarter of 2008, and in connection therewith restated the corresponding items of segment information for earlier periods. Our current operating segments are Completion and Remedial Services, Fluid Services, Well Servicing, and Contract Drilling. These segments were selected based on changes in management's resource allocation and performance assessment in making decisions regarding the Company. Prior to 2008, Contract Drilling was included in our Well Servicing segment and also in 2008, Well Site Construction Services was consolidated with our Fluid Services segment. The following is a description of our current business segments:

- *Completion and Remedial Services.* Our completion and remedial services segment (43% of our revenues in 2011) currently operates our fleet of pressure 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, nitrogen units, and water treatment. The largest portion of this business segment consists of pumping services focused on cementing, acidizing and fracturing services in niche markets. In July 2011, we acquired 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").
- *Fluid Services.* Our fluid services segment (27% of our revenues in 2011) currently utilizes our fleet of 890 fluid service trucks and related assets, including specialized tank trucks, storage tanks, water wells, disposal facilities 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 (27% of our revenues in 2011) currently operates our fleet of 417 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 (3% of our revenues in 2011) currently operates 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 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 81% of onshore oil production and 93% of 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 128 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 eight 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 an average of 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 eight 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 thoroughly 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. As oil and natural gas prices increased from 2007 through most of 2008, oil and gas companies increased their drilling and workover activities. In the last part of 2008, oil and natural gas prices declined rapidly, resulting in decreased drilling and workover activities. During the second half of 2009, oil prices began to increase and 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 through most of 2009 and remained depressed through 2011, 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 during the last months of 2011. 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 increased activity.

The table below sets forth average closing prices for the Cushing WTI Spot Oil Price and the EIA average wellhead price for natural gas since 2007:

Period	Cushing WTI Spot Oil Price ($/bbl)	Average Wellhead Price Natural Gas ($/mcf)
1/1/07 — 12/31/07	$72.34	$6.38
1/1/08 — 12/31/08	99.67	8.07
1/1/09 — 12/31/09	61.65	3.66
1/1/10 — 12/31/10	79.39	4.48
1/1/11 — 12/31/11	94.87	3.98*

* The December 2011 average wellhead price for natural gas was not available at the time this report was filed; therefore the average price through November 2011 was used:

Source: U.S. Department of Energy.

Increased expenditures for exploration and production activities generally drives the increased demand for our services. Rising oil and natural gas prices from 2007 through the first half of 2008 and the corresponding increase in onshore oil exploration and production spending led to expanded drilling and well service activity, as the U.S. land-based drilling rig count increased approximately 4% during 2007. With the rapid decline in oil and natural gas prices in the second half of 2008, there was a decrease in the land-based drilling rig count of approximately 3% during 2008 and 31% during 2009. In 2010, as oil and natural gas prices improved, the land-based drilling rig count increased approximately 45%. In 2011, oil prices improved further and the land-based drilling rig count increased approximately 18%, according to Baker Hughes. The increase in oil prices in the past year resulted in both higher utilization of those rigs and increases in the rates being charged.

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, coiled tubing, 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, and currently operates 222 pressure pumping units, with approximately 271,000 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. As of December 31, 2011, we also operated 12 coiled tubing units 49 air compressor packages, including foam circulation units, for underbalanced drilling, 12 wireline units for cased-hole measurement and pipe recovery services and 26 snubbing units.

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 pressure 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, 2011:

	Market Area						
	Ark-La-Tex	**Mid-Continent**	**Gulf Coast**	**Rocky Mountain**	**Permian Basin**	**Appalachia**	**Total**
Pressure Pumping Units	15	117	0	65	25	0	222
Coiled Tubing Units	0	4	1	7	0	0	12
Air/Foam Packages	0	5	0	30	14	0	49
Wireline Units	0	4	0	0	8	0	12
Rental and Fishing Tool Stores	0	8	1	4	9	0	22
Snubbing Units	13	5	0	0	0	8	26

Our pumping services business focuses primarily on lower horsepower cementing, acidizing and fracturing services markets. Currently, there are several pressure 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 pressure 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 pressure 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 pressure 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. Pressure pumping 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 pressure 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 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, 2011:

	Market Area					
	Rocky Mountain	**Permian Basin**	**Ark-La-Tex**	**Gulf Coast**	**Mid-Continent**	**Total**
Fluid Service Trucks	110	370	168	164	78	890
Salt Water Disposal Wells	0	27	24	8	11	70
Fresh/Brine Water Stations	1	38	1	2	0	42
Fluid Storage Tanks	728	1,027	923	406	212	3,296

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 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.

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. We currently own and operate 890 fluid service trucks equipped with a fluid hauling capacity of up to 150 barrels. 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 is 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.

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 the second quarter of 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 417 well servicing rigs as of December 31, 2011, including 162 newbuilds since October 2004 and 63 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, 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, 2011. 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	0	1	7	3	0	0	1	12
Light Duty	<90 tons	3	1	0	8	0	0	9	21
Medium Duty	≥90<125 tons	113	30	21	46	47	2	22	281
Heavy Duty	≥125 tons	53	6	4	6	10	6	8	93
24-Hour	≥125 tons	2	0	0	0	0	0	4	6
Inland Barge	≥125 tons	0	4	0	0	0	0	0	4
Total		171	42	32	63	57	8	44	417

We operate a total of 417 well servicing rigs, the third largest fleet in the United States. Based on the most recent publicly available information, Key Energy Services is our largest competitor, with an estimated total of

787 domestic rigs, and Nabors Industries is our second largest competitor, with an estimated 575 domestic rigs. Our only other competitors operating more than 100 rigs are Complete Production Services, with an estimated 300 domestic rigs and Forbes Energy Services, with an estimated 172 domestic rigs. Excluding the rigs operated by Nabors Industries in California, where we do not compete, we believe we have the second largest rig fleet in the United States.

The total number of rigs owned by us and the four other companies referenced above is approximately 2,251, or 71% of the available fleet owned by member companies of the AESC, the major trade association of well site service providers. The remaining 29% of the well servicing rigs are owned by more than 100 local and regional companies. The December 2011 monthly activity survey conducted by the AESC indicated that 67% of the rigs owned were active.

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 require 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.

We acquired six used drilling rigs during 2011 from several different companies.

Properties

Our principal executive offices are located at 500 W. Illinois, Suite 100, Midland, Texas 79701. We currently conduct our business from 128 area offices, 69 of which we own and 59 of which we lease. Each office typically includes a yard, administrative office and maintenance facility. Of our 128 area offices, 67 are located in Texas, 15 are in Oklahoma, 11 are in Colorado, 10 are in New Mexico, eight are in Wyoming, four are in Louisiana, four are in North Dakota, two are in Arkansas, two are in Montana, two are in Kansas, two are in Utah, and one is in Pennsylvania.

Customers

We serve numerous major and independent oil and gas companies that are active in our core areas of operations. During 2011, 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., combined own approximately 43% 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 2011, or at the state level. For example at the state level, Wyoming adopted rules in 2010 requiring operators to disclose chemical additives in hydraulic fracturing fluids. In addition, the Texas Railroad Commission adopted rules on December 13, 2011 that require oil and gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells permitted after February 1, 2012 and the Colorado Oil and Gas Conservation Commission adopted rules in December 2011 requiring operators to disclose chemical ingredients used in hydraulic fracturing treatments beginning on April 1, 2012. 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 and Kansas. 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 and Louisiana 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. 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.

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 2011. 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 beginning in 2011. 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 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, 2011, we employed approximately 5,600 people, with approximately 82% 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.

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.

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, 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 but another downturn to former levels is possible. 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 $61.65, $79.39 and $94.87 per barrel in 2009, 2010 and 2011, respectively, and the average wellhead price for natural gas, as recorded by the EIA, was $3.66, $4.48 and $3.98 per Mcf for 2009, 2010 and 2011, respectively. The full 2011 average wellhead price for natural gas was not available at the time this report was filed; therefore, the average price through November 2011 was used.

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, 2010, we invested approximately $63.6 million in cash for capital expenditures, excluding acquisitions. For the year ended December 31, 2011, we invested approximately $221.8 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.

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 oil-oriented operating areas were to deteriorate or if adverse market conditions in our natural gas-oriented operating areas persist, utilization rates may decline.

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 2010 and 2011, our top five customers accounted for 24% and 24%, respectively, 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.

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 7.125% Senior Notes due 2016 and 7.75% Senior Notes due 2019.

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 Kenneth V. Huseman, our President and Chief Executive Officer, or other key personnel could disrupt our operations. Although we have entered into employment agreements with Mr. Huseman 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.

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.

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 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 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, including certain onshore oil and natural gas production activities, which may affect certain of our or our customers' 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 beginning in 2011. 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 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 2011. 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 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 has begun the process of drafting guidance relating to such practices. In addition, repeal of the SDWA exclusion of hydraulic fracturing has been advocated by certain advocacy organizations and others in the public. In March 2011, companion bills entitled the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act were reintroduced in the United States Senate and House of Representatives. These bills, which are currently under consideration by Congress, would 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, Wyoming adopted rules in 2010 requiring operators to disclose chemical additives in hydraulic fracturing fluids. In addition, the Texas Railroad Commission adopted rules on December 13, 2011 that require oil and gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells permitted after February 1, 2012 and the Colorado Oil and Gas Conservation Commission adopted rules in December 2011 requiring operators to disclose chemical ingredients used in hydraulic fracturing treatments beginning on April 1, 2012. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a study of the potential environmental impacts of hydraulic fracturing, the initial results of which are expected to be available by late 2012 and the final results of which are 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. 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," and in December 2011, the FWS announced a six-month delay on its final determination. The lesser prairie chicken, 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.

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, 2011, our total debt was $781.2 million, including the aggregate principal amount due under our 7.125% Senior Notes due 2016 of $225.0 million, the aggregate principal amount due under our 7.75% Senior Notes due 2019 of $475.0 million and capital lease obligations in the aggregate amount of $81.2 million. There were no borrowings and $18.8 million of letters of credit outstanding under our $225.0 million revolving credit facility as of December 31, 2011. For the year ended December 31, 2011, we made cash interest payments totaling $47.1 million.

We issued $275.0 million of 7.75% Senior Notes due 2019 in February 2011 and used a portion of the net proceeds from the offering to retire our outstanding 11.625% Senior Secured Notes, and in June 2011, we issued an additional $200.0 million of 7.75% Senior Notes due 2019. We also entered into a $165.0 million revolving credit facility in February 2011 (the "Revolving Credit Facility"), and pursuant to Amendment No. 2 thereto on July 15, 2011, the aggregate commitments thereunder were increased to $225.0 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 7.125% Senior Notes due 2016 and our 7.75% Senior Notes due 2019 impose restrictions on us that may affect our ability to successfully operate our business.

Our Revolving Credit Facility and the indentures governing our 7.125% Senior Notes due 2016 and our 7.75% Senior Notes due 2019 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 7.125% Senior Notes, our 7.75% Senior Notes 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.

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 14, 2012, 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.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. *MARKET PRICE 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, 2010 and 2011, respectively:

	High	Low
2010:		
First Quarter	$11.12	$ 7.71
Second Quarter	$10.68	$ 7.13
Third Quarter	$ 9.65	$ 7.17
Fourth Quarter	$17.06	$ 8.63
2011:		
First Quarter	$25.51	$14.62
Second Quarter	$31.47	$23.62
Third Quarter	$37.59	$13.26
Fourth Quarter	$22.45	$13.14

As February 14, 2012, we had 42,633,430 shares of common stock outstanding held by approximately 228 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, 2011:

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(1)	787,450	$14.55	2,356,941
Equity compensation plans not approved by security holders	—	—	—
Total	787,450	$14.55	2,356,941

(1) Consists of the Basic Energy Services, Inc. Fourth Amended and Restated 2003 Incentive Plan (as amended effective May 26, 2009).

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, 2011 (dollars in thousands, except average price paid per share):

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet be Purchased Under the Program
October 1, 2011 — October 31, 2011	0	$0.00	0	$0
November 1, 2011 — November 30, 2011	0	$0.00	0	$0
December 1, 2011 — December 31, 2011	0	$0.00	0	$0
Total	0	$0.00	0	$0

(1) These shares 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.

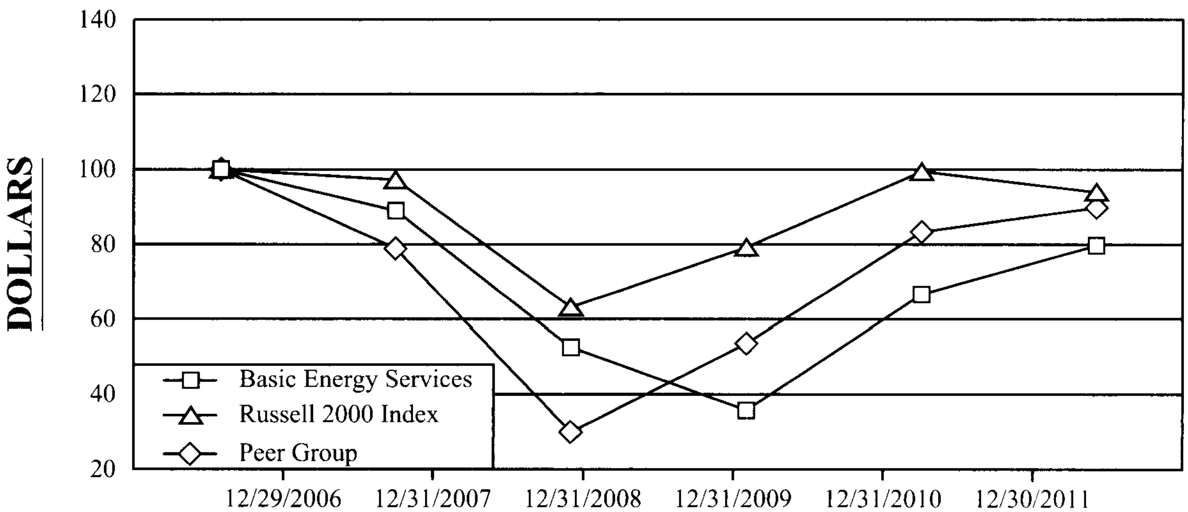
Performance Graph

The following is a line graph comparing cumulative, total shareholder return from December 29, 2006 through December 30, 2011 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., Complete Production Services, Inc., Tetra Technologies, Inc. and Pioneer Drilling Company.

The graph assumes investments of $100 on December 29, 2006 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.

December 29, 2006 to December 30, 2011



Value of $100 Invested at December 29, 2006, December 31, 2007, December 31, 2008, December 31, 2009, December 31, 2010 and December 31, 2011

	Basic Energy Services	Peer Group	Russell 2000
December 29, 2006	$100.00	$100.00	$100.00
December 31, 2007	$ 89.05	$ 79.00	$ 97.25
December 31, 2008	$ 52.90	$ 30.37	$ 63.41
December 31, 2009	$ 36.11	$ 53.85	$ 79.40
December 31, 2010	$ 66.86	$ 83.49	$ 99.49
December 31, 2011	$ 79.92	$ 89.88	$ 94.07

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 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,				
	2011	2010	2009	2008	2007
	(Dollars in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Completion and remedial services	$ 537,134	$261,436	$ 134,818	$ 304,326	$ 240,692
Fluid services	332,010	241,164	214,822	315,768	259,324
Well servicing	333,057	204,872	160,614	343,113	342,697
Contract drilling	41,054	20,767	16,373	41,735	34,460
Total revenues	1,243,255	728,239	526,627	1,004,942	877,173
Expenses:					
Completion and remedial services	297,276	156,573	95,287	165,574	125,948
Fluid services	211,959	178,152	159,079	203,205	165,327
Well servicing	228,723	156,885	121,618	215,243	205,132
Contract drilling	28,154	15,250	13,604	28,629	22,510
General and administration(a)	142,264	107,781	104,253	115,319	99,042
Depreciation and amortization	154,341	135,001	132,520	118,607	93,048
Loss (gain) on disposal of assets	447	2,856	2,650	76	477
Goodwill impairment	—	—	204,014	22,522	—
Total expenses	1,063,164	752,498	833,025	869,175	711,484
Operating income (loss)	180,091	(24,259)	(306,398)	135,767	165,689
Net interest expense	(52,299)	(46,368)	(32,386)	(24,630)	(25,136)
Loss on early extinguishment of debt	(49,366)	—	(3,481)	—	(230)
Bargain Purchase gain	—	1,772	—	—	—
Other income (expense)	525	499	1,198	12,235	176
Income (loss) from continuing operations before income taxes	78,951	(68,356)	(341,067)	123,372	140,499
Income tax (expense) benefit	(31,788)	24,793	87,529	(55,134)	(52,766)
Net income (loss)	47,163	(43,563)	(253,538)	68,238	87,733
Net income (loss) available to common stockholders	$ 47,163	$ (43,563)	$(253,538)	$ 68,238	$ 87,733
Basic earnings (loss) per share of common stock:	$ 1.17	$ (1.10)	$ (6.39)	$ 1.67	$ 2.19
Diluted earnings (loss) per share of common stock:	$ 1.14	$ (1.10)	$ (6.39)	$ 1.64	$ 2.13
Other Financial Data:					
Cash flows from operating activities	$ 279,455	$ 49,383	$ 89,205	$ 212,827	$ 198,591
Cash flows from investing activities	(419,967)	(97,879)	(62,864)	(197,302)	(294,103)
Cash flows from financing activities	171,052	(28,943)	(12,119)	3,669	136,088
Capital expenditures:					
Acquistions, net of cash acquired	218,347	50,278	7,816	110,913	199,673
Property and equipment	221,839	63,579	43,367	91,890	98,536

(a) Includes approximately $7,955, $5,666, $5,152, $4,149, and $3,964, of non-cash stock compensation expense for the years ended December 31, 2011, 2010, 2009, 2008, and 2007, respectively.

	As of December 31,				
	2011	2010	2009	2008	2007
	(Dollars in thousands)				
Balance Sheet Data:					
Cash and cash equivalents	$ 78,458	$ 47,918	$ 125,357	$ 111,135	$ 91,941
Property and equipment, net	856,412	625,702	666,642	740,879	636,924
Total assets	1,459,928	1,029,813	1,039,541	1,310,711	1,143,609
Long-term debt	748,976	474,628	475,845	454,260	406,306
Stockholders' equity	359,703	301,923	340,149	595,004	524,821

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 nine separate acquisitions from January 1, 2009 to December 31, 2011. Our hydraulic horsepower capacity for pumping services increased from 139,000 at December 31, 2009 to 271,000 at December 31, 2011. Our weighted average number of fluid service trucks increased from 814 in the first quarter of 2009 to 875 in the fourth quarter of 2011. Our weighted average number of well servicing rigs increased from 414 in the first quarter of 2009 to 417 in the fourth quarter of 2011. Our weighted average number of drilling rigs increased from nine in the first quarter of 2009 to ten in the fourth quarter of 2011. 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,					
	2011		2010		2009	
Revenues:						
Completion and remedial services	$ 537.1	43%	$261.4	36%	$134.8	26%
Fluid services	332.0	27%	241.1	33%	214.8	41%
Well servicing	333.1	27%	204.9	28%	160.6	30%
Contract drilling	41.1	3%	20.8	3%	16.4	3%
Total revenues	$1,243.3	100%	$728.2	100%	$526.6	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.

In the latter part of 2008, there were significant decreases in oil and natural gas prices, which caused significantly lower utilization of our services in the fourth quarter of 2008. In 2009, natural gas prices continued to decline from prices experienced in the fourth quarter of 2008 while oil prices increased over the same period. This decrease in natural gas prices, coupled with adverse changes in the capital markets, resulted in lower demand for our services and increased price competition during 2009, as a number of oil and gas producers reduced their budgets for 2009. 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. This trend in oil prices has caused utilization and pricing for our services to increase in our oil-based operating areas, while utilization and pricing for our services in our natural gas-based operating areas throughout 2011 have remained depressed due to low natural gas prices. We expect oil prices in 2012 to remain above levels necessary to support increased capital spending programs for workover and drilling programs as well as routine maintenance. We believe that the outlook for natural gas prices in 2012 will continue to be uncertain, which will cause our customers to remain cautious in their spending until natural gas prices gain strength and stability. We expect that the supply of available equipment combined with current demand from our customers will result in utilization levels in 2012 across all of our business segments being consistent with the utilization levels experienced in the last half of 2011.

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 2009 through 2011, we grew through acquisitions and capital expenditures. During 2009, we completed one acquisition, which was not considered significant. During 2010, we completed four acquisitions that complemented our existing business segments, none of which were considered significant. During 2011, we completed four acquisitions, of which the Maverick Companies was 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 2009 Acquisitions

Team Snubbing Services, Inc.

On December 28, 2009, we acquired substantially all of the assets of Team Snubbing Services, Inc. for total consideration of $7.0 million in cash. This acquisition operates in our completion and remedial services segment.

Selected 2010 Acquisitions

During 2010, we made four acquisitions that complemented our existing business segments. These included, among others:

Taylor Rig, LLC

On May 3, 2010, we acquired all the assets of Taylor Rig, LLC for total consideration of $8.7 million in cash. This acquisition has been included in our well servicing segment.

Platinum Pressure Services, Inc.

On December 16, 2010, we acquired all of the outstanding stock of Platinum Pressure Services, Inc. ("Platinum") and Admiral Well Service, Inc., a wholly owned subsidiary of Platinum, for total cash consideration of $39.9 million. This acquisition operates in our completion and remedial services and well servicing segments.

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 servicing segment.

Segment Overview

Completion and Remedial Services

In 2011, our completion and remedial services segment represented 43% 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, water treatment, 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 271,000 horsepower at December 31, 2011 compared to 142,000 horsepower and 139,000 horsepower at December 31, 2010 and December 31, 2009, respectively.

Our rental and fishing tool business operates 22 rental and fishing tool stores in selected markets as of December 31, 2011.

Our snubbing services operate 26 units throughout our geographic footprint as of December 31, 2011. 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 business, coiled tubing services, nitrogen services, water treatment and the underbalanced drilling services business. For a description of our wireline, underbalanced drilling services, coiled tubing services, nitrogen services, water treatment, and snubbing, 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, 2009, 2010 and 2011 (dollars in thousands):

	Revenues	Segment Profits %
2009:		
First Quarter	$ 37,259	31%
Second Quarter	$ 29,373	27%
Third Quarter	$ 32,592	29%
Fourth Quarter	$ 35,594	30%
Full Year	$134,818	29%
2010:		
First Quarter	$ 45,234	34%
Second Quarter	$ 61,533	39%
Third Quarter	$ 73,725	41%
Fourth Quarter	$ 80,944	43%
Full Year	$261,436	40%
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%

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 2011, 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 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. 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, 2009, 2010 and 2011 (dollars in thousands):

	Weighted Average Number of Fluid Service Trucks	Trucking Hours	Revenue Per Fluid Service Truck	Segment Profits Per Fluid Service Truck	Segment Profits %
2009:					
First Quarter	814	474,500	$ 80	$ 25	31%
Second Quarter	808	395,600	$ 61	$ 17	28%
Third Quarter	805	428,800	$ 62	$ 14	23%
Fourth Quarter	794	433,300	$ 64	$ 13	20%
Full Year	805	1,732,200	$267	$ 69	26%
2010:					
First Quarter	791	431,700	$ 66	$ 14	22%
Second Quarter	797	468,600	$ 74	$ 19	26%
Third Quarter	789	475,200	$ 80	$ 20	25%
Fourth Quarter	782	476,100	$ 85	$ 27	31%
Full Year	790	1,851,600	$305	$ 80	26%
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%

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 2011, our well servicing segment represented 27% 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, 2009, 2010 and 2011. The revenues do not include revenues associated with rig manufacturing operations:

	Weighted Average Number of Rigs	Rig Hours	Rig Utilization Rate	Revenue Per Rig Hour	Profits Per Rig Hour	Segment Profits %
2009:						
First Quarter	414	132,300	44.7%	$369	$ 90	24%
Second Quarter	414	110,500	37.3%	$329	$ 78	24%
Third Quarter	414	122,900	41.5%	$313	$ 76	24%
Fourth Quarter	410	119,500	40.8%	$309	$ 77	25%
Full Year	413	485,200	41.1%	$331	$ 80	24%
2010:						
First Quarter	405	135,700	46.9%	$308	$ 71	23%
Second Quarter	404	153,900	53.3%	$316	$ 83	26%
Third Quarter	404	159,400	55.2%	$319	$ 74	21%
Fourth Quarter	407	164,400	56.5%	$331	$ 90	24%
Full Year	405	613,400	53.0%	$319	$ 81	23%
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%

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 2011, our contract drilling segment represented 3% 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. In the fourth quarter of 2010, we converted three of our drilling rigs to well service rigs.

The following is an analysis of our contract drilling segment for each of the quarters and years in the years ended December 31, 2009, 2010 and 2011 (dollars in thousands):

	Weighted Average Number of Rigs	Rig Operating Days	Revenue Per Drilling Day	Profits (Loss) Per Drilling Day	Segment Profits %
2009:					
First Quarter	9	248	$14,700	$1,500	10%
Second Quarter	9	314	$12,700	$2,100	16%
Third Quarter	9	391	$10,600	$2,200	20%
Fourth Quarter	9	417	$11,000	$2,200	20%
Full Year	9	1,370	$12,000	$2,000	17%
2010:					
First Quarter	6	420	$ 9,000	$1,200	14%
Second Quarter	6	527	$10,000	$2,900	29%
Third Quarter	6	523	$10,600	$2,700	26%
Fourth Quarter	6	536	$11,500	$3,800	33%
Full Year	6	2,006	$10,400	$2,800	27%
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%

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. Provisions for asset impairment are charged to income when the sum of the estimated future cash flows, on an undiscounted basis, is less than the asset's carrying amount. When impairment is indicated, an impairment charge is recorded 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 $750,000, $750,000, and $250,000, 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. Our goodwill is considered to have an indefinite useful economic life and 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.

We performed an assessment of goodwill as of March 31, 2009. A "triggering event" requiring this assessment was deemed to have occurred because the oil and natural gas services industry continued to decline in the first quarter of 2009 and our common stock price declined by 50% from December 31, 2008 to March 31, 2009. For Step One of the impairment testing, we tested three reporting units for goodwill impairment: well servicing, fluid services, and completion and remedial services. Our contract drilling reporting unit did not carry any goodwill and was not subject to the test.

To estimate the fair value of the reporting units, we used a weighting of the discounted cash flow method and the public company guideline method of determining fair value of a business unit. We weighted the discounted cash flow method 85% and public company guideline method 15%, due to differences between our reporting units and the peer companies' size, profitability and diversity of operations. In order to validate the reasonableness of the estimated fair values obtained for the reporting units, a reconciliation of fair value to market capitalization was performed for each unit on a stand-alone basis. A control premium, derived from market transaction data, was used in this reconciliation to ensure that fair values were reasonably stated in conjunction with our capitalization. The measurement date for our common stock price and market capitalization was the closing price on March 31, 2009.

Based on the results of Step One of the impairment test, impairment was indicated in all three of the assessed reporting units. As such, we were required to perform Step Two assessment on all three of the reporting units. Step Two requires the allocation of the estimated fair value to the tangible and intangible assets and liabilities of the respective unit. This assessment indicated that $204.1 million was considered impaired as of March 31, 2009. This non-cash charge eliminated all of our existing goodwill as of March 31, 2009.

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 2009, 2010 and 2011 using a grant date fair-value based method, resulting in compensation expense for stock-based awards being recorded in our consolidated statements of income. 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.

Asset Retirement Obligations. We record the fair value of an asset retirement obligation as a liability in the period in which we incur 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 settlement of obligations.

Results of Operations

The results of operations between periods may not be comparable, primarily due to the significant decline in the oil and natural gas industry throughout 2009 and recovery throughout 2010 and 2011, as well as the Company's growth in asset base during 2011.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Revenues. Revenues increased by 71% to $1.2 billion in 2011 from $728.2 million in 2010. This increase was primarily due to the recovery of the oil and gas industry in 2011. Our acquisitions at the end of 2010 and during 2011 also increased our revenues, with the Maverick Companies acquisition adding approximately $62.4 million of revenue since being acquired in the third quarter of 2011.

Completion and remedial services revenues increased by 105% to $537.1 million in 2011 as compared to $261.4 million in 2010. The increase in revenue between these periods was due to increased utilization and improved prices of our pressure pumping equipment, due to higher drilling and completion activity. The increased revenues also reflect the impact of the Maverick Companies acquisition in the third quarter of 2011, which added approximately $62.4 million of segment revenue. Total hydraulic horsepower was 271,000 and 142,000 at December 31, 2011 and December 31, 2010, respectively.

Fluid services revenues increased by 38% to $332.0 million in 2011 compared to $241.1 million in 2010. Our weighted average number of fluid service trucks increased 8% to 850 in 2011 from 790 in 2010, and our revenue per fluid service truck increased 28% to $391,000 in 2011 compared to $305,000 in 2010, which reflects the expansion of our truck and frac tank fleets and the increase in utilization and improved pricing for our services.

Well servicing revenues increased by 63% to $333.1 million in 2011 compared to $204.9 million in 2010. This increase in revenue was due to the increase in rig utilization to 70% during 2011 from 53% during 2010, reflecting the improvement of the industry, particularly in oil-dominated geographic areas. We also experienced an increase of 19% in revenue per rig hour to $380 during 2011 from $319 during 2010, due to increased demand. Our average number of well servicing rigs increased to 414 during 2011 compared to 405 in 2010, primarily due to the acquisition of Platinum late in the fourth quarter of 2010 and Pat's P&A, Inc. in the third quarter of 2011.

Contract drilling revenues increased by 98% to $41.1 million in 2011 compared to $20.8 million in 2010. The number of rig operating days increased to 2,889 in 2011 compared to 2,006 in 2010. This increase was due to the addition of six drilling rigs during 2011 and increases in new well starts in the Permian Basin, the region in which all of our drilling rigs operate.

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 51% to $766.1 million in 2011 from $506.9 million in 2010. 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 90% to $297.3 million in 2011 as compared to $156.6 million in 2010, due primarily to increased activity levels as well as the Maverick Companies acquisition, which added approximately $29.8 million to the segment's direct operating expenses since it was acquired in the third quarter of 2011. Segment profits increased to 45% of revenues in 2011 compared to 40% in 2010, due to higher levels of completion and pumping services and improved pricing for our services.

Direct operating expenses for the fluid services segment increased by 19% to $212.0 million in 2011 as compared to $178.2 million in 2010, due to higher activity levels. Segment profits were 36% of revenues in 2011 and 26% of revenues in 2010, due to increases in pricing and utilization of equipment.

Direct operating expenses for the well servicing segment increased by 46% to $228.7 million in 2011 as compared to $156.9 million in 2010, due primarily to the 35% increase in rig hours to 829,600 in 2011 from 613,400 in 2010. Segment profits increased to 31% of revenues in 2011 compared to 23% in 2010, due to improved utilization of equipment and pricing of services.

Direct operating expenses for the contract drilling segment increased by 85% to $28.2 million in 2011 as compared to $15.3 million in 2010 due primarily to a 44% increase in rig operating days in 2011. Segment profits for this segment were 31% of revenues in 2011 compared to 27% in 2010, due primarily to increased dayrates and an increase in the number of drilling rigs.

General and Administrative Expenses. General and administrative expenses increased by 32% to $142.3 million in 2011 from $107.8 million in 2010, which included $8.0 million and $5.7 million of stock-based compensation expense in 2011 and 2010, respectively. The increase was primarily due to increased personnel and incentive compensation costs, including payroll taxes, the full year effect of the general and administrative expense from the Platinum acquisition that was completed in December 2010 and the six months of general and administrative expense from the Maverick Companies acquisition that was completed in July 2011.

Depreciation and Amortization Expenses. Depreciation and amortization expenses were $154.3 million in 2011, as compared to $135.0 million in 2010, reflecting the increase in the size of and investment in our asset base. We invested $218.3 million for acquisitions, $57.7 million for capital leases and an additional $221.8 million for cash capital expenditures in 2011.

Loss on Early Extinguishment of Debt. In the first quarter of 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 entered into in September 2010.

Interest Expense. Interest expense increased by 16% to $53.9 million in 2011 from $46.5 million in 2010. The increased expense was due to the issuance of an aggregate of $475.0 million of 7.75% senior notes in the first half of 2011.

Income Tax Expense. Income tax expense was $31.8 million in 2011, as compared to a tax benefit of $24.8 million in 2010. Our effective tax rate was approximately 40% in 2011 and our effective tax rate was approximately 36% in 2010. The increase in the effective tax rate was primarily due to the change in the mix and amount of state taxes.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Revenues. Revenues increased by 38% to $728.2 million in 2010 from $526.6 million in 2009. This increase was primarily due to increased expenditures by our customers for our services, especially in oil-producing areas that had significant increases in exploration, completion of new wells and workovers performed on existing wells.

Completion and remedial services revenues increased by 94% to $261.4 million in 2010 as compared to $134.8 million in 2009. The increase in revenue between these periods was due to increased utilization of our pressure pumping equipment, resulting from higher drilling and completion activity as well as improved pricing for our services. Total hydraulic horsepower was 142,000 and 139,000 at December 31, 2010 and December 31, 2009, respectively.

Fluid services revenues increased by 12% to $241.1 million in 2010 compared to $214.8 million in 2009. Our weighted average number of fluid service trucks decreased 2% to 790 in 2010 from 805 in 2009, and our revenue per fluid service truck increased to $305,000 in 2010 compared to $267,000 in 2009, which reflects an increase in utilization and improved pricing for our services.

Well servicing revenues increased by 28% to $204.9 million in 2010 compared to $160.6 million in 2009. This increase was due to the increase in rig utilization to 53% during 2010 from 41% during 2009. This increase in rig utilization was offset by a decrease of 4% in revenue per rig hour to $319 during 2010 from $331 during 2009, due to increased price competition. Pricing per hour increased steadily throughout the second half of 2010. Our average number of well servicing rigs decreased to 405 during 2010 compared to 413 in 2009, due to the retirement of older, less efficient rigs.

Contract drilling revenues increased by 27% to $20.8 million in 2010 compared to $16.4 million in 2009. The number of rig operating days increased to 2,006 in 2010 compared to 1,370 in 2009. This increase in revenues was due to an increase in new well starts in the Permian Basin, the region in which all of our drilling rigs operate, and was offset by lower dayrates.

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 30% to $506.9 million in 2010 from $389.6 million in 2009. This increase was due to the higher activity levels in all of our segments and was offset by cost-cutting measures implemented as a result of the decline in revenues in 2009.

Direct operating expenses for the completion and remedial services segment increased by 64% to $156.6 million in 2010 as compared to $95.3 million in 2009 due primarily to increased activity levels. Segment profits increased to 40% of revenues in 2010 compared to 29% in 2009, due to higher levels of completion and pumping services and improved pricing for our services.

Direct operating expenses for the fluid services segment increased by 12% to $178.2 million in 2010 as compared to $159.1 million in 2009, due to higher activity levels. Segment profits were 26% of revenues in both 2010 and 2009.

Direct operating expenses for the well servicing segment increased by 29% to $156.9 million in 2010 as compared to $121.6 million in 2009, due primarily to the 26% increase in rig hours to 613,400 in 2010 from 485,200 in 2009. Segment profits decreased slightly to 23% of revenues in 2010 compared to 24% in 2009.

Direct operating expenses for the contract drilling segment increased by 12% to $15.3 million in 2010 as compared to $13.6 million in 2009 due primarily to a 46% increase in rig operating days in 2010, which was offset by the mix of day rate work and footage work between 2010 and 2009. Segment profits for this segment were 27% of revenues in 2010 compared to 17% in 2009, due primarily to increased dayrates.

General and Administrative Expenses. General and administrative expenses increased by 3% to $107.8 million in 2010 from $104.3 million in 2009, which included $5.7 million and $5.2 million of stock-based compensation expense in 2010 and 2009, respectively. The increase from 2009 primarily reflects higher salary expenses related to the increase in the number of employees along with the reversal of pay reductions enacted at the end of the first quarter of 2009 and higher incentive compensation.

Depreciation and Amortization Expenses. Depreciation and amortization expenses were $135.0 million in 2010, as compared to $132.5 million in 2009, reflecting the increase in the size of and investment in our asset base. We invested $50.3 million for acquisitions, $23.4 million for capital leases and an additional $63.6 million for cash capital expenditures in 2010.

Goodwill Impairment. In the first half of 2009, we recorded a non-cash charge totaling $204.0 million for impairment of all of the goodwill associated with our well servicing, fluid services, and completion and remedial services segments as of March 31, 2009. There was no impairment of goodwill in 2010.

Interest Expense. Interest expense increased by 41% to $46.5 million in 2010 from $32.9 million in 2009. The increase was primarily due to the effect in 2010 of the issuance of $225.0 million of 11.625% senior secured notes in July 2009, the proceeds of which were used to retire our previous $225.0 million revolving credit facility.

Income Tax Expense. Income tax benefit was $24.8 million in 2010, as compared to a benefit of $87.5 million in 2009. Our effective benefit rate was approximately 36% in 2010 and our effective benefit rate was approximately 26% in 2009. The lower effective benefit rate in 2009 related to the goodwill write-down in the first quarter of 2009 and was due to differences in the taxable nature of the impaired goodwill. A portion of the goodwill came from stock acquisitions, which have zero tax bases.

Liquidity and Capital Resources

Currently, our primary capital resources are net cash flows from our operations and utilization of capital leases and our $225.0 million revolving credit facility. As of December 31, 2011, we had cash and cash equivalents of $78.5 million compared to $47.9 million as of December 31, 2010. 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 $279.5 million for the year ended December 31, 2011 as compared to $49.4 million in 2010 and $89.2 million in 2009. The increase in 2011 was due primarily to the increase in profitability resulting from higher revenues and margins offset by the increases in accounts receivable. In July 2011, we received aggregate federal income tax refunds of approximately $80.1 million relating to our 2009 and 2010 tax returns. The decrease in operating cash flows in 2010 compared to 2009 was primarily due to lower profitability being partially offset by the collection of accounts receivable generated in prior periods.

Capital Expenditures

Capital expenditures are the main component of our investing activities. Cash capital expenditures (including for acquisitions) for 2011 were $440.2 million as compared to $113.9 million in 2010, and $51.2 million in 2009. Cash capital expenditures have increased from 2009 through 2011 as the utilization of our assets has improved along with increased profitability. Through our capital lease program, we also added assets of approximately $57.7 million, $23.4 million and $18.6 million in 2011, 2010 and 2009, respectively.

In 2012, we have currently planned capital expenditures of approximately $250 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.

Capital Resources and Financing

Our current primary capital resources are cash flow from our operations, our $225.0 million revolving credit facility, the ability to enter into capital leases and a cash balance of $78.5 million at December 31, 2011. In 2011, 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, 2011 (in thousands):

	Obligations Due in Periods Ended December 31,				
Contractual Obligations	**Total**	**2012**	**2013-2014**	**2015-2016**	**Thereafter**
Long-term debt (excluding capital leases)	$ 700,000	$ —	$ —	$225,000	$475,000
Interest on long-term debt	340,219	52,844	105,688	89,656	92,031
Capital leases	81,199	34,115	39,481	7,470	133
Operating leases	19,038	4,369	7,006	5,446	2,217
Asset retirement obligations	1,845	204	420	211	1,010
Other long-term liabilities	5,327	4,019	1,308	—	—
Total	$1,147,628	$95,551	$153,903	$327,783	$570,391

Our long-term debt as of December 31, 2011, excluding capital leases, consisted of our $225.0 million 7.125% Senior Notes and our $475.0 million 7.75% Senior Notes. 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.

7.125% Senior Notes due 2016

In April 2006, we completed a private offering of $225.0 million aggregate principal amount of 7.125% Senior Notes due April 15, 2016 (the "7.125% Senior Notes"). The 7.125% Senior Notes are jointly and severally guaranteed by each of our restricted subsidiaries (currently all of our subsidiaries other than three immaterial subsidiaries). As of December 31, 2011, these three subsidiaries held no assets and performed no operations. The net proceeds from the offering were used to retire the outstanding balance of our Term B Loan balance and to pay down the outstanding balance under our previous credit facility. Remaining proceeds were used for general corporate purposes, including acquisitions.

We issued the Senior Notes pursuant to an indenture, dated as of April 12, 2006, by and among us, the guarantor parties thereto and The Bank of New York Trust Company, N.A., as trustee (the "7.125% Senior Notes Indenture").

Interest on the 7.125% Senior Notes accrues at a rate of 7.125% per year. Interest on the 7.125% Senior Notes is payable in cash semi-annually in arrears on April 15 and October 15 of each year. The 7.125% Senior Notes mature on April 15, 2016. The 7.125% Senior Notes and the guarantees are unsecured and rank equally with all of our and the guarantors' existing and future unsecured and unsubordinated obligations. The 7.125% Senior Notes and the guarantees rank senior in right of payment to any of our and the guarantors' existing and future obligations that are, by their terms, expressly subordinated in right of payment to the 7.125% Senior Notes and the guarantees. The 7.125% Senior Notes and the guarantees are effectively subordinated to our and the guarantors' secured obligations to the extent of the value of the assets securing such obligations.

The 7.125% Senior Notes Indenture contains covenants that limit the ability of us and 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 restricted subsidiaries; and
- sell assets or consolidate or merge with or into other companies.

These limitations are subject to a number of important qualifications and exceptions.

Upon an Event of Default (as defined in the 7.125% Senior Notes Indenture), the trustee or the holders of at least 25% in aggregate principal amount of the 7.125% Senior Notes then outstanding may declare all of the amounts outstanding under the 7.125% Senior Notes to be due and payable immediately.

We may, at our option, redeem all or part of the 7.125% Senior Notes at a redemption price equal to 100% of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest, if any, to the date of redemption.

Following a change of control, as defined in the 7.125% Senior Notes Indenture, we will be required to make an offer to repurchase all or any portion of the 7.125% Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest to the date of repurchase.

11.625% Senior Secured Notes due 2014

On July 31, 2009, we issued $225.0 million aggregate principal amount of 11.625% Senior Secured Notes due 2014 (the "Senior Secured Notes") in a private placement. The Senior Secured Notes were jointly and severally, and unconditionally, guaranteed on a senior secured basis initially by all of our current subsidiaries other than two immaterial subsidiaries.

The net proceeds from the issuance of the Senior Secured Notes were $207.7 million after discounts of $12.1 million and offering expenses of $5.2 million. We used the net proceeds from the offering, along with other funds, to repay all outstanding indebtedness under our $225.0 million revolving credit facility, which we terminated in connection with the offering.

The Senior Secured Notes and the related guarantees were issued pursuant to an indenture dated as of July 31, 2009 (the "Senior Secured Notes Indenture"), by and among us, the guarantors party thereto and The Bank of New York Mellon Trust Company, N.A., as trustee. The obligations under the Senior Secured Notes Indenture were secured as set forth in the Senior Secured Notes Indenture and in a related Security Agreement (the "Secured Notes Security Agreement"), in favor of the trustee, by a first-priority lien (other than Permitted Collateral Liens, as defined in the Senior Secured Notes Indenture) in favor of the trustee, on the collateral described in the Secured Notes Security Agreement.

Interest on the Senior Secured Notes accrued at a rate of 11.625% per year. Interest on the Senior Secured Notes was payable semi-annually in arrears on February 1 and August 1 of each year, commencing on February 1, 2010. The Senior Secured Notes provided for a maturity on August 1, 2014.

The Senior Secured Notes Indenture contained 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 our affiliates;
- limit dividends or other payments by our restricted subsidiaries to us; and
- sell assets (including collateral under the Secured Notes Security Agreement), or consolidate or merge with or into other companies.

These limitations were subject to a number of important exceptions and qualifications.

On February 1, 2011, we announced a cash tender offer and consent solicitation with respect to any and all of the $225.0 million aggregate outstanding principal amount of the Senior Secured Notes. On February 15, 2011, we completed the closing for 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. The tender offer expired on March 2, 2011, and all of our obligations under the Senior Secured Notes Indenture have been satisfied and no Senior Secured Notes are outstanding.

7.75% Senior Notes due 2019

On February 15, 2011, we successfully completed the issuance and sale of $275.0 million and on June 13, 2011, we successfully completed the issuance and sale of an additional $200.0 million, for an aggregate principal amount of $475.0 million of 7.75% Senior Notes due 2019 (the "7.75% Senior Notes"). The 7.75% Senior 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 7.75% Senior Notes and the guarantees rank

(i) equally in right of payment with any of our and the subsidiary guarantors' existing and future senior indebtedness, including our existing 7.125% Senior Notes and the related guarantees, and (ii) effectively junior to all existing or future liabilities of our subsidiaries that do not guarantee the 7.75% Senior Notes and to our and the subsidiary guarantors' existing or future secured indebtedness to the extent of the value of the collateral therefor.

The 7.75% Senior 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 purchase price for the $275.0 million of 7.75% Senior Notes issued on February 15, 2011 and guarantees was 100.000% of their principal amount and the purchase price for the $200.0 million of 7.75% Senior Notes issued on June 13, 2011 and guarantees was 101.000%, plus accrued interest from February 15, 2011. We received net proceeds from the issuance of the 7.75% Senior Notes of approximately $464.6 million after premiums and offering expenses. We used a portion of the net proceeds from the offering to fund our tender offer and consent solicitation for our Senior Secured Notes and to redeem the Senior Secured Notes not purchased in the tender offer. We also used a portion of the net proceeds from the June Senior Notes offering to fund the $186.3 million purchase price for the Maverick Companies acquisition completed in July 2011 and for general corporate purposes.

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

The 7.75% Senior 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 7.75% Senior Notes Indenture are subject to important exceptions and qualifications. Additionally, during any period of time that the 7.75% Senior Notes have a Moody's rating of Baa3 or higher or an Standard & Poor's rating of BBB- or higher and no default has occurred and is then continuing, certain of the restrictive covenants contained in the 7.75% Senior Notes Indenture will cease to apply.

We may, at our option, redeem all or part of the 7.75% Senior 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 7.75% Senior Notes issued under the 7.75% Senior 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 7.75% Senior 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 7.75% Senior Notes issued under the 7.75% Senior 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 7.75% Senior Notes at a redemption price equal to 100% of the principal amount of the 7.75% Senior Notes, plus an applicable premium and accrued and unpaid interest to the date of redemption.

Following a change of control, as defined in the 7.75% Senior Notes Indenture, we will be required to make an offer to repurchase all or a portion of the 7.75% Senior 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 7.75% Senior Notes, we terminated our previous $30.0 million secured revolving credit facility with Capital One, National Association, and entered into a new $165.0 million revolving credit facility (the "Credit Agreement") 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, 2011, 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.

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 2.25% based on our leverage ratio or (ii) Eurodollar loans, at a variable base interest rate plus a margin ranging from 2.50% to 3.25% 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 2.50:1.00;
- a maximum consolidated leverage ratio not to exceed:
- 4.25:1.00 for the quarter ending March 31, 2011; and
- 4.00:1.00 after March 31, 2011; and
- a maximum consolidated senior secured leverage ratio of 2.00:1.00.

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 $18.8 million of letters of credit outstanding under the Credit Agreement as of December 31, 2011, giving us $206.2 million of available borrowing capacity. At December 31, 2011, 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, 2011, we had total capital leases of approximately $81.2 million.

Losses on Extinguishment of Debt

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, 2011 and December 31, 2010, 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, 2011, we had approximately $83.3 million of NOL carryforwards.

Recent Accounting Pronouncements

In January 2010, the FASB issued ASU No. 2010-06, "*Improving Disclosures about Fair Value Measurements*" ("ASU No. 2010-06"). ASU No. 2010-06 requires the disclosure of significant transfers in and out of Level 1 and Level 2 fair value measurements. It also requires that Level 3 fair value measurements present information about purchases, sales, issuances and settlements. Fair value disclosures should also disclose valuation techniques and inputs used to measure both recurring and nonrecurring fair value measurements. This update became effective for Basic on January 1, 2010 except for the disclosures about purchases, sales, issuances, and settlements in the roll forward in activity in Level 3 fair value measurements, which became effective on January 1, 2011. This update did not change the techniques Basic uses to measure fair value and has not had a material impact on its consolidated financial statements.

In December 2010, the FASB issued ASU No. 2010-29, "*Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations*" ("ASU 2010-29"). ASU 2010-29 addresses diversity in the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. If a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The Company adopted ASU 2010-29 on January 1, 2011. This update had no impact on the Company's financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, "*Comprehensive Income: Presentation of Comprehensive Income*" ("ASU 2011-05"). ASU 2011-05 requires companies to present the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements of net income and other comprehensive income. This statement is effective for interim and annual periods beginning after December 15, 2011. Early adoption is permitted and the amendments in this update will be applied retrospectively. Basic currently does not have any items of other comprehensive income and therefore does not expect a material impact on its consolidated financial statements.

In September 2011, the FASB issued ASU No. 2011-08, "*Intangibles – Goodwill and Other*" ("ASU 2011-08"). ASU 2011-08 allows a qualitative assessment of whether it is more likely than not that a reporting unit's fair value is less than its carrying amount before applying the two-step goodwill impairment test. If it is more likely than not that the fair value of a reporting unit is less than its carrying amount, then the two-step impairment test for that reporting unit would be performed. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011 and early adoption is permitted. Basic early adopted this accounting standard update and it has changed the process Basic uses to determine if goodwill is impaired but it has not had a material impact on Basic's 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, 2011, 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, 2011, based on criteria established in *Internal Control — Integrated Framework* 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, 2011, 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 the Maverick Companies, Pat's P&A, Inc., and Cryogas Services LLP (collectively, the "Acquisitions") during 2011, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, the Acquisitions' internal control over financial reporting associated with total assets of $219.9 million and total revenues of $68.6 million included in the consolidated financial statements of Basic Energy Services, Inc. and subsidiaries as of and for the year ended December 31, 2011.

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/ Kenneth V. Huseman	/s/ Alan Krenek
Kenneth V. Huseman Chief Executive Officer	Alan Krenek 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 (the Company) internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company'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, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company acquired the Maverick Companies, Pat's P&A, Inc., and Cryogas Services LLP (collectively, the "Acquisitions") during 2011, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, the Acquisitions' internal control over financial reporting associated with total assets of $219.9 million and total revenues of $68.6 million included in the consolidated financial statements of Basic Energy Services, Inc. and subsidiaries as of and for the year ended December 31, 2011. 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, 2011 and 2010, 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, 2011, and our report dated February 24, 2012 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Dallas, Texas
February 24, 2012

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 (the Company) as of December 31, 2011 and 2010, 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, 2011. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedules. 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 schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Basic Energy Services, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement 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, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Dallas, Texas
February 24, 2012

Basic Energy Services, Inc.

Consolidated Balance Sheets
(in thousands, except share data)

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 78,458	$ 47,918
Trade accounts receivable, net of allowance of $1,230 and $3,078, respectively	254,446	150,364
Accounts receivable — related parties	65	42
Income tax receivable	314	79,480
Inventories	34,963	21,556
Prepaid expenses	8,667	5,425
Other current assets	6,768	18,193
Deferred tax assets	39,154	8,290
Total current assets	422,835	331,268
Property and equipment, net	856,412	625,702
Deferred debt costs, net of amortization	16,131	6,835
Goodwill	82,571	16,150
Other intangible assets, net of amortization	74,637	45,833
Other assets	7,342	4,025
Total assets	$1,459,928	$1,029,813
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 56,957	$ 40,477
Accrued expenses	65,096	51,237
Current portion of long-term debt	34,115	24,231
Other current liabilities	315	3,309
Total current liabilities	156,483	119,254
Long-term debt, net of discount or premium on notes of $1,892 and $9,425 at December 31, 2011 and 2010, respectively	748,976	474,628
Deferred tax liabilities	183,551	123,393
Other long-term liabilities	11,215	10,615
Commitments and contingencies		
Stockholders' equity:		
Preferred stock; $.01 par value; 5,000,000 shares authorized; none designated or issued at December 31, 2011 and December 31, 2010, respectively	—	—
Common stock; $.01 par value; 80,000,000 shares authorized; 42,530,809 shares issued and 42,486,645 shares outstanding at December 31, 2011; and 42,394,809 shares issued and 41,310,447 shares outstanding at December 31, 2010	425	424
Additional paid-in capital	345,619	335,927
Retained earnings (deficit)	13,659	(27,544)
Treasury stock, at cost 44,164 and 1,084,362 shares at December 31, 2011 and 2010, respectively	—	(6,884)
Total stockholders' equity	359,703	301,923
Total liabilities and stockholder's equity	$1,459,928	$1,029,813

See accompanying notes to consolidated financial statements.

Basic Energy Services, Inc.

Consolidated Statements of Operations and Comprehensive Income (Loss)
(Dollars in thousands, except per share amounts)

	Years ended December 31		
	2011	**2010**	**2009**
Revenues:			
Completion and remedial services	$ 537,134	$261,436	$ 134,818
Fluid services	332,010	241,164	214,822
Well servicing	333,057	204,872	160,614
Contract drilling	41,054	20,767	16,373
Total revenues	1,243,255	728,239	526,627
Expenses:			
Completion and remedial services	297,276	156,573	95,287
Fluid services	211,959	178,152	159,079
Well servicing	228,723	156,885	121,618
Contract drilling	28,154	15,250	13,604
General and administrative, including stock-based compensation of $7,955, $5,666 and $5,152 in 2011, 2010 and 2009 respectively	142,264	107,781	104,253
Depreciation and amortization	154,341	135,001	132,520
Loss on disposal of assets	447	2,856	2,650
Goodwill impairment	—	—	204,014
Total expenses	1,063,164	752,498	833,025
Operating income (loss)	180,091	(24,259)	(306,398)
Other income (expense):			
Interest expense	(53,886)	(46,471)	(32,949)
Interest income	1,587	103	563
Gain on bargain purchase	—	1,772	—
Loss on early extinguishment of debt	(49,366)	—	(3,481)
Other income	525	499	1,198
Income (loss) from continuing operations before income taxes	78,951	(68,356)	(341,067)
Income tax benefit (expense)	(31,788)	24,793	87,529
Net income (loss) available to common stockholders	47,163	(43,563)	(253,538)
Basic earnings per share of common stock:			
Net income (loss) available to common stockholders	$ 1.17	$ (1.10)	$ (6.39)
Diluted earnings per share of common stock:			
Net income (loss) available to common stockholders	$ 1.14	$ (1.10)	$ (6.39)

See accompanying notes to consolidated financial statements.

Basic Energy Services, Inc.

Consolidated Statements of Stockholders' Equity
(in thousands, except share data)

	Common Stock		Additional Paid-In Capital	Treasury Stock	Retained Earnings (Deficit)	Total Stockholders' Equity
	Shares	Amount				
Balance — December 31, 2008	41,734,485	$417	$325,785	$ (8,371)	$ 277,173	$ 595,004
Issuances of restricted stock	660,324	7	(7)	462	(462)	—
Amortization of share based compensation	—	—	5,127	—	—	5,127
Treasury stock issued as compensation to Chairman of the Board	—	—	—	43	(19)	24
Purchase of treasury stock	—	—	—	(6,151)	—	(6,151)
Exercise of stock options	—	—	(352)	54	(19)	(317)
Net loss	—	—	—	—	(253,538)	(253,538)
Balance — December 31, 2009	42,394,809	424	330,553	(13,963)	23,135	340,149
Issuances of restricted stock	—	—	—	6,896	(6,896)	—
Amortization of share based compensation	—	—	5,666	—	—	5,666
Purchase of treasury stock	—	—	—	(359)	—	(359)
Exercise of stock options / vesting of restricted stock	—	—	(292)	542	(220)	30
Net loss	—	—	—	—	(43,563)	(43,563)
Balance — December 31, 2010	42,394,809	424	335,927	(6,884)	(27,544)	301,923
Issuances of restricted stock	—	—	(32)	5,783	(5,751)	—
Amortization of share based compensation	—	—	7,955	—	—	7,955
Purchase of treasury stock	—	—	—	(1,872)	—	(1,872)
Exercise of stock options / vesting of restricted stock	136,000	1	1,769	2,973	(209)	4,534
Net income	—	—	—	—	47,163	47,163
Balance — December 31, 2011	42,530,809	$425	$345,619	$ —	$ 13,659	$ 359,703

See accompanying notes to consolidated financial statements.

Basic Energy Services, Inc.

Consolidated Statements of Cash Flows
(in thousands)

	Years ended December 31,		
	2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ 47,163	$ (43,563)	$(253,538)
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	154,341	135,001	132,520
Gain on bargain purchase	—	(1,772)	—
Goodwill impairment	—	—	204,014
Accretion on asset retirement obligation	124	162	149
Change in allowance for doubtful accounts	(1,848)	(1,679)	(1,081)
Amortization of deferred financing costs	2,349	1,567	1,414
Amortization of discount or premium on notes	6,385	1,937	740
Non-cash compensation	7,955	5,666	5,152
Loss on early extinguishment of debt (non-cash)	3,940	—	3,481
Premium on retirement of 11.625% senior secured notes	36,179	—	—
Loss on disposal of assets	447	2,856	2,650
Deferred income taxes	30,695	(5,993)	(25,230)
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	(88,863)	(55,304)	88,149
Inventories	(12,057)	(2,411)	975
Prepaid expenses and other current assets	(1,344)	4,800	(1,444)
Other assets	(2,853)	(949)	(1,010)
Accounts payable	12,140	16,002	(5,441)
Excess tax expense (benefits) from exercise of employee stock options / vesting of restricted stock	—	292	351
Income tax receivable	79,166	(17,986)	(58,981)
Other liabilities	(6,941)	3,074	(343)
Accrued expenses	12,477	7,683	(3,322)
Net cash provided by operating activities	279,455	49,383	89,205
Cash flows from investing activities:			
Purchase of property and equipment	(221,839)	(63,579)	(43,367)
Proceeds from sale of assets	20,843	2,521	4,134
Change in restricted cash	—	14,123	(14,123)
Payments for other long-term assets	(624)	(666)	(1,692)
Payments for businesses, net of cash acquired	(218,347)	(50,278)	(7,816)
Net cash used in investing activities	(419,967)	(97,879)	(62,864)
Cash flows from financing activities:			
Proceeds from debt	498,850	—	241,697
Payments of debt	(278,696)	(28,253)	(239,543)
Premium on retirement of 11.625% senior secured notes	(36,179)	—	—
Purchase of treasury stock	(1,872)	(359)	(6,151)
Excess tax benefits (expense) from exercise of employee stock options / vesting of restricted stock	—	(292)	(351)
Tax withholding from exercise of stock options	(3,175)	(108)	(5)
Exercise of employee stock options	7,709	430	38
Deferred loan costs and other financing activities	(15,585)	(361)	(7,804)
Net cash provided by or (used) in financing activities	171,052	(28,943)	(12,119)
Net increase (decrease) in cash and equivalents	30,540	(77,439)	14,222
Cash and cash equivalents — beginning of year	47,918	125,357	111,135
Cash and cash equivalents — end of year	$ 78,458	$ 47,918	$ 125,357

See accompanying notes to consolidated financial statements.

BASIC ENERGY SERVICES, INC.

Notes to Consolidated Financial Statements
December 31, 2011, 2010, and 2009

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, Wyoming, North Dakota, Colorado, Utah and Montana.

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

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
- Asset retirement obligation

Revenue Recognition

Completion and Remedial 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 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 values of the services.

Fluid Services — Fluid services consist primarily of the sale, transportation, storage and disposal of fluids used in drilling, production and maintenance of oil and natural gas wells. 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 and 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 — 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 these jobs 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.

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, 2011 and 2010. 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, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
7.125% Senior Notes	$225,000	$228,375	$225,000	$218,250
11.625% Senior Secured Notes	—	—	225,000	249,750
7.75% Senior Notes	475,000	482,125	—	—

7.125% Senior Notes, 11.625% Senior Secured Notes, and 7.75% Senior Notes: The fair value of our long-term notes is based upon the quoted market prices at December 31, 2011 and December 31, 2010.

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:

Building and improvements	20-30 years
Well servicing units and equipment	3-15 years
Fluid services equipment	5-10 years
Brine and fresh water stations	15 years
Frac/test tanks	10 years
Pressure 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 $20.8 million net of accumulated amortization of $4.6 million, and $10.7 million net of accumulated amortization of $3.9 million at December 31, 2011 and December 31, 2010, respectively. Amortization of deferred debt costs totaled approximately $2.3 million, $1.6 million and $1.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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 for 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 $165.0 million 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 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.

The Company performed an assessment of goodwill as of March 31, 2009. A "triggering event" requiring this assessment was deemed to have occurred because the oil and gas services industry continued to decline in the first quarter of 2009 and the Company's common stock price declined by 50% from December 31, 2008 to March 31, 2009. For Step One of the impairment testing, the Company tested three reporting units for goodwill impairment: well servicing, fluid services, and completion and remedial services. The Company's contract drilling reporting unit does not carry any goodwill, and was not subject to the test.

To estimate the fair value of the reporting units, the Company primarily used level 3 inputs from the fair value hierarchy, which included a weighting of the discounted cash flow method and the public company guideline method of determining fair value of a business unit. The Company weighted the discounted cash flow method 85% and public company guideline method 15%, due to differences between the Company's reporting units and the peer companies' size, profitability and diversity of operations. In order to validate the reasonableness of the estimated fair values obtained for the reporting units, a reconciliation of fair value to market capitalization was performed for each unit on a stand-alone basis. A control premium, derived from market transaction data, was used in this reconciliation to ensure that fair values were reasonably stated in conjunction with the Company's capitalization. The measurement date for the Company's common stock price and market capitalization was the closing price on March 31, 2009.

Based on the results of Step One of the impairment test, impairment was indicated in all three of the assessed reporting units. As such, the Company was required to perform Step Two assessment on all three of the reporting units. Step Two requires the allocation of the estimated fair value to the tangible and intangible assets and liabilities of the respective unit. This assessment indicated that $204.1 million was considered impaired as of March 31, 2009. This non-cash charge eliminated all of the Company's existing goodwill as of March 31, 2009.

The changes in the carrying amount of goodwill for the year ended December 31, 2011, are as follows (in thousands):

	Completion and Remedial Services	Fluid Services	Well Servicing	Contract Drilling	Total
Balance as of December 31, 2010	$10,771	$ 488	$4,891	$—	$16,150
Goodwill additions	61,598	3,598	1,225	—	66,421
Balance as of December 31, 2011	$72,369	$4,086	$6,116	$—	$82,571

Basic had trade names of $1.9 million as of December 31, 2011 and $1.8 million as of December 31, 2010, respectively. 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 $78.2 million and $48.0 million as of December 31, 2011 and 2010, respectively. The gross carrying amount of non-compete agreements subject to amortization totaled approximately $7.6 million and $4.9 million at December 31, 2011 and 2010, respectively. The gross carrying amount of other intangible assets subject to amortization was $1.1 million and $746,000 as of December 31, 2011 and December 31, 2010, respectively. Accumulated amortization related to these intangible assets totaled approximately $14.1 million and $9.6 million at December 31, 2011 and 2010, respectively. Amortization expense for the years ended December 31, 2011, 2010 and 2009 was approximately $5.5 million, $3.4 million, and $3.1 million, respectively. Amortization expense for the next five succeeding years is estimated to be approximately $6.6 million, $6.2 million, $6.2 million, $6.1 million, and $5.6 million in 2012, 2013, 2014, 2015, and 2016, respectively. Other intangibles net of accumulated amortization allocated to reporting units as of December 31, 2011 were $58.0 million, $3.7 million, $6.4 million and $4.6 million for completion and remedial services, fluid services, well servicing, and contract drilling, respectively.

Amortizable Intangible Assets at December 31, 2011 (in thousands):	
Customer Relationships	$ 78,159
Accumulated Amortization Customer Relationships	(10,937)
Non-Compete Agreements	7,552
Accumulated Amortization Non-Compete Agreements	(3,111)
Other Intangible Assets	1,126
Accumulated Amortization Other Intangible Assets	(91)
Total Amortizable Intangible Assets	$ 72,698

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

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 2009, 2010, and 2011 using a grant date fair-value based method, resulting in compensation expense for stock-based awards being recorded in our consolidated statements of income. 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 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

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.

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 2011, 2010, or 2009.

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, 2011, Basic did not have any items of other comprehensive income (loss).

Reclassifications

Certain reclassifications of prior year financial statement amounts have been made to conform to current year presentations.

Recent Accounting Pronouncements

In January 2010, the FASB issued ASU No. 2010-06, "*Improving Disclosures about Fair Value Measurements*" ("ASU No. 2010-06"). ASU No. 2010-06 requires the disclosure of significant transfers in and out of Level 1 and Level 2 fair value measurements. It also requires that Level 3 fair value measurements present information about purchases, sales, issuances and settlements. Fair value disclosures should also disclose valuation techniques and inputs used to measure both recurring and nonrecurring fair value measurements. This update became effective for Basic on January 1, 2010 except for the disclosures about purchases, sales, issuances, and settlements in the roll forward in activity in Level 3 fair value measurements, which became effective on January 1, 2011. This update did not change the techniques Basic uses to measure fair value and has not had a material impact on its consolidated financial statements.

In December 2010, the FASB issued ASU No. 2010-29, "*Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations*" ("ASU 2010-29"). ASU 2010-29 addresses diversity in the interpretation of the pro forma revenue and earnings disclosure requirements for business combinations. If a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The Company adopted ASU 2010-29 on January 1, 2011. This update had no impact on the Company's financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, *"Comprehensive Income: Presentation of Comprehensive Income"* ("ASU 2011-05"). ASU 2011-05 requires companies to present the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements of net income and other comprehensive income. This statement is effective for interim and annual periods beginning after December 15, 2011. Early adoption is permitted and the amendments in this update will be applied retrospectively. Basic currently does not have any items of other comprehensive income and therefore does not expect a material impact on its consolidated financial statements.

In September 2011, the FASB issued ASU No. 2011-08, *"Intangibles — Goodwill and Other"* ("ASU 2011-08"). ASU 2011-08 allows a qualitative assessment of whether it is more likely than not that a reporting unit's fair value is less than its carrying amount before applying the two-step goodwill impairment test. If it is more likely than not that the fair value of a reporting unit is less than its carrying amount, then the two-step impairment test for that reporting unit would be performed. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011 and early adoption is permitted. Basic early adopted this accounting standard update and it has changed the process Basic uses to determine if goodwill is impaired but it has not had a material impact on Basic's consolidated financial statements.

3. Acquisitions

In 2011, 2010 and 2009, 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, except for the acquisitions completed in 2011 whose values are provisional (in thousands):

	Closing Date	Total Cash Paid (net of cash acquired)
Team Snubbing Services, Inc.	December 28, 2009	$ 6,985
Total 2009		$ 6,985
Rocky Mountain Cementers, Inc.	March 1, 2010	$ 687
New Tech Systems, Inc	April 20, 2010	900
Taylor Rig, LLC	May 3, 2010	8,734
Platinum Pressure Services, Inc.	December 16, 2010	39,942
Total 2010		$ 50,263
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	10,900
Cryogas Services LLP	September 8, 2011	11,085
Total 2011		$218,338

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 2009, 2010 or 2011 are not material, either individually or when aggregated, to the reported results of operations.

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 since the date of acquisition was $62.4 million. 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 preliminary estimated fair value of the assets acquired and liabilities assumed at the date of acquisition for the Maverick Companies (in thousands):

Current Assets	$ 17,036
Property and Equipment	92,856
Other Intangible Assets(1)	29,400
Goodwill(2)	58,167
Other Non-Current Assets	464
Total Assets Acquired	$197,923
Current Liabilities	$ 9,534
Deferred Income Taxes	—
Total Liabilities Assumed	$ 9,534
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, intelectual 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.

The following unaudited pro-forma results of operations have been prepared as though the Maverick Companies acquisition had been completed on January 1, 2010. Pro-forma amounts are based on the purchase price allocation of the significant acquisition and are not necessarily indicative of the results that may be reported in the future (in thousands, except per share data).

	Twelve Months Ended December 31,	
	2011	2010
Revenues	$1,298,636	$780,515
Net income (loss)	$ 51,166	$(51,108)
Earnings per common share — basic	$ 1.27	$ (1.29)
Earnings per common share — diluted	$ 1.23	$ (1.29)

In preparing the pro-forma financials Basic added $9.4 million of depreciation for 2010 and $6.3 million of depreciation for 2011. Amortization expense, for the amortization of intangible assets, of $2.4 million and $1.2 million was included for 2010 and 2011, respectively. Interest expense of $14.4 million and $6.5 million was included for 2010 and 2011, respectively.

4. Property and Equipment

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

	December 31, 2011	December 31, 2010
Land	$ 11,314	$ 5,361
Buildings and improvements	47,710	32,047
Well service units and equipment	447,743	416,015
Fluid services equipment	179,495	148,989
Brine and fresh water stations	13,000	10,969
Frac/test tanks	246,816	151,379
Pressure pumping equipment	246,931	171,892
Construction equipment	29,281	27,799
Contract drilling equipment	93,728	44,181
Disposal facilities	78,632	66,388
Vehicles	54,238	39,844
Rental equipment	46,851	43,502
Aircraft	4,251	4,251
Software	23,595	22,296
Other	15,690	7,345
	1,539,275	1,192,258
Less accumulated depreciation and amortization	682,863	566,556
Property and equipment, net	$ 856,412	$ 625,702

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, 2011	December 31, 2010
Light vehicles	$ 28,794	$ 25,800
Well service units and equipment	1,671	1,791
Fluid services equipment	83,544	65,874
Pressure pumping equipment	24,260	18,293
Construction equipment	1,341	1,269
Software	16,896	15,548
Other	557	244
	157,063	128,819
Less accumulated amortization	60,455	56,087
	$ 96,608	$ 72,732

Amortization of assets held under capital leases of approximately \$22.0 million, \$21.2 million and \$20.4 million for the years ended December 31, 2011, 2010 and 2009, 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, 2011	December 31, 2010
Credit Facilities:		
Revolver	\$ —	\$ —
7.125% Senior Notes	225,000	225,000
11.625% Senior Secured Notes	—	225,000
7.75% Senior Notes	475,000	—
Unamortized (discount) premium	1,892	(9,425)
Capital leases and other notes	81,199	58,284
	783,091	498,859
Less current portion	34,115	24,231
	\$748,976	\$474,628

7.125% Senior Notes due 2016

On April 12, 2006, Basic issued \$225.0 million of 7.125% Senior Notes due April 2016 (the "7.125% Senior Notes") in a private placement. Proceeds from the sale of the 7.125% Senior Notes were used to retire the outstanding balance on Basic's \$90.0 million Term B Loan and to pay down approximately \$96.0 million under Basic's previous revolving credit facility. The 7.125% Senior Notes are unsecured. Under the terms of the sale of the 7.125% Senior Notes, Basic was required to take appropriate steps to offer to exchange other 7.125% Senior Notes with the same terms that have been registered with the Securities and Exchange Commission for the private placement 7.125% Senior Notes. Basic completed the exchange offer for all of the 7.125% Senior Notes on October 16, 2006.

Basic issued the 7.125% Senior Notes pursuant to an indenture, dated as of April 12, 2006, by and among Basic, the guarantor parties thereto and The Bank of New York Trust Company, N.A., as trustee (the "7.125% Senior Notes Indenture"). Interest on the 7.125% Senior Notes accrues at a rate of 7.125% per year. Interest payments on the 7.125% Senior Notes are due semi-annually, on April 15 and October 15.

The 7.125% Senior Notes are redeemable at the option of Basic at the specified redemption price as described in the 7.125% Senior Notes Indenture.

Following a change of control, as defined in the 7.125% Senior Notes Indenture, Basic will be required to make an offer to repurchase all or any portion of the 7.125% Senior Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest to the date of repurchase.

The 7.125% Senior Notes Indenture contains covenants that, among other things, limit the ability of Basic and its restricted 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 restricted subsidiaries; and sell assets or consolidate or merge with or into other companies. These limitations are subject to a number of important qualifications and exceptions set forth in the 7.125% Senior Notes Indenture. At December 31, 2011, Basic was in compliance with the restrictive covenants under the 7.125% Senior Notes Indenture.

As part of the issuance of the above-mentioned 7.125% Senior Notes, Basic incurred debt issuance costs of approximately $5.2 million, which are being amortized to interest expense using the effective interest method over the term of the 7.125% Senior Notes.

The 7.125% Senior 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. As of December 31, 2011, these three subsidiaries held no assets and performed no operations. Basic Energy Services, Inc., the ultimate parent company, does not have any independent operating assets or operations.

7.75% Senior Notes due 2019

On February 15, 2011, Basic successfully completed the issuance and sale of $275.0 million and on June 13, 2011, Basic successfully completed the issuance and sale of an additional $200.0 million, for an aggregate principal amount of $475.0 million of 7.75% Senior Notes due 2019 (the "7.75% Senior Notes"). The 7.75% Senior 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 7.75% Senior 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 7.125% Senior Notes and the related guarantees, and (ii) effectively junior to all existing or future liabilities of Basic's subsidiaries that do not guarantee the 7.75% Senior Notes and to Basic's and the subsidiary guarantors' existing or future secured indebtedness to the extent of the value of the collateral therefore.

The 7.75% Senior Notes 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"). Under the terms of the sale of the 7.75% Senior Notes, Basic was required to take appropriate steps to offer to exchange other 7.75% Senior Notes with the same terms that have been registered with the Securities and Exchange Commission for the private placement 7.75% Senior Notes. Basic completed the exchange offer for all of the 7.75% Senior Notes on November 15, 2011.

The purchase price for the $275.0 million of 7.75% Senior Notes issued on February 15, 2011 was 100.000% of their principal amount and the purchase price for the $200.0 million of 7.75% Senior 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 7.75% Senior 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 its tender offer and consent solicitation for its 11.625% Senior Secured Notes and to redeem any of the Senior Secured Notes not purchased in the tender offer. Basic used a portion of 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 7.75% Senior Notes were issued pursuant to an indenture dated as of February 15, 2011 (the "7.75% Senior Notes Indenture"), by and among Basic, the guarantors party thereto and Wells Fargo Bank, N.A., as trustee . Interest on the 7.75% Senior Notes accrues from and including February 15, 2011 at a rate of 7.75% per year. Interest on the 7.75% Senior Notes is payable semi-annually in arrears on February 15 and August 15 of each year, commencing on August 15, 2011. The 7.75% Senior Notes mature on February 15, 2019.

The 7.75% Senior 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 its 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 7.75% Senior Notes Indenture are subject to important exceptions and qualifications set forth in the 7.75% Senior Notes Indenture. At December 31, 2011, Basic was in compliance with the restrictive covenants under the 7.75% Senior Notes Indenture.

Basic may, at its option, redeem all or part of the 7.75% Senior 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 7.75% Senior Notes issued under the 7.75% Senior 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 7.75% Senior 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 7.75% Senior Notes issued under the 7.75% Senior 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 7.75% Senior Notes at a redemption price equal to 100% of the principal amount of the 7.75% Senior Notes, plus an applicable premium and accrued and unpaid interest to the date of redemption.

Following a change of control, as defined in the 7.75% Senior Notes Indenture, Basic will be required to make an offer to repurchase all or a portion of the 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 7.75% Senior Notes offering, Basic entered into a new $165.0 million revolving credit facility (the "Credit Agreement") 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. On July 15, 2011, Basic exercised the accordion feature and amended the Credit Agreement to increase our total credit available from $165.0 million to $225.0 million. 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 assets of Basic and the guarantors as collateral under a related Security Agreement (the "Security Agreement"). As of December 31, 2011, the non-guarantor subsidiaries held no assets and performed no operations.

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 2.25% based on Basic's leverage ratio or (ii) Eurodollar loans, at a variable base interest rate plus a margin ranging from 2.50% to 3.25% 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 Basic's 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 2.50:1.00;
- a maximum consolidated leverage ratio not to exceed:
- 4.25:1.00 for the quarter ending March 31, 2011; and
- 4.00:1.00 after March 31, 2011; and
- a maximum consolidated senior secured leverage ratio of 2.00:1.00.

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 $18.8 million of letters of credit outstanding under the Credit Agreement as of December 31, 2011. At December 31, 2011, Basic had availability under the Credit Agreement of $206.2 million. At December 31, 2011, 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 us to maintain a minimum debt service coverage ratio of 1.05 to 1.00. At December 31, 2011, Basic was in compliance with this covenant.

As of December 31, 2011 the aggregate maturities of debt, including capital leases, for the next five years and thereafter are as follows (in thousands):

	Debt	Capital Leases
2012	$ —	$34,115
2013	—	23,164
2014	—	16,317
2015	—	6,765
2016	225,000	705
Thereafter	475,000	133
	$700,000	$81,199

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

	Years ended December 31,		
	2011	2010	2009
Cash payments for interest	$47,077	$43,814	$21,357
Commitment and other fees paid	915	19	159
Amortization of debt issuance costs and discount on senior secured notes	2,495	3,504	2,153
Change in accrued interest	3,347	4	9,277
Capitalized interest	—	(887)	—
Other	52	17	3
	$53,886	$46,471	$32,949

Losses on Extinguishment of Debt

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,		
	2011	2010	2009
Current:			
Federal	$ (57)	$(19,190)	$(58,972)
State	1,150	390	(3,327)
Total	1,093	(18,800)	(62,299)
Deferred:			
Federal	27,940	(5,045)	(23,217)
State	2,755	(948)	(2,013)
Total	30,695	(5,993)	(25,230)
Total income tax expense (benefit)	$31,788	$(24,793)	$(87,529)

Basic paid no federal income taxes during 2011 or 2010. Basic paid federal income taxes of $243,000 during 2009.

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,		
	2011	2010	2009
Statutory federal income tax	$27,633	$(23,925)	$(119,374)
Meals and entertainment	630	473	374
State taxes, net of federal benefit	3,504	(847)	(4,227)
Impairment of non-dedcutible goodwill	—	—	35,586
Changes in estimates and other	21	(494)	112
	$31,788	$(24,793)	$ (87,529)

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,	
	2011	2010
Deferred tax assets:		
Receivables allowance	$ 456	$ 1,132
Inventory	177	42
Asset retirement obligation	492	443
Accrued liabilities	8,695	9,148
Operating loss carryforward	32,946	5,472
Goodwill and intangibles	8,298	10,399
Deferred compensation	6,732	5,770
Total deferred tax assets	57,796	32,406
Deferred tax liabilities:		
Property and equipment	(199,795)	(145,410)
Prepaid expenses	(2,398)	(2,099)
Total deferred tax liabilities	(202,193)	(147,509)
Net deferred tax liability	(144,397)	(115,103)
Recognized as:		
Deferred tax assets — current	39,154	8,290
Deferred tax liabilities — non-current	(183,551)	(123,393)
Net deferred tax liability	$(144,397)	$(115,103)

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, 2011 or 2010.

Interest is recorded in interest expense and penalties are recorded in income tax expense. We had no interest or penalties related to an uncertain tax positions during 2011. 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 2010 federal income tax return is under examination at this time.

As of December 31, 2011, Basic had approximately $83.3 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. 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.

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.

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, 2011, the future minimum lease payments under non-cancelable operating leases are as follows (in thousands):

Year ended December 31,	
2012	4,369
2013	3,779
2014	3,227
2015	3,042
2016	2,404
Thereafter	2,217

Rent expense approximated $17.2 million, $12.8 million and $13.4 million for 2011, 2010 and 2009, respectively.

Basic leases rights for the use of various brine and fresh water wells and disposal wells ranging in terms from month-to-month up to 99 years. The above table reflects the future minimum lease payments if the lease contains a periodic rental. However, the majority of these leases require payments based on a royalty percentage or a volume usage.

Employment Agreements

Under the employment agreement with Mr. Huseman, Chief Executive Officer and President of Basic, effective December 31, 2006 through December 31, 2012, Mr. Huseman is currently entitled to an annual salary of $700,000. Under this employment agreement, Mr. Huseman is eligible from time to time to receive grants of stock options and other long-term equity incentive compensation under our Amended and Restated 2003 Incentive Plan. In addition, upon a qualified termination of employment, Mr. Huseman would be entitled to three times his annual base salary plus his current annual incentive target bonus for the full year in which the termination of employment occurred. If employment is terminated for certain reasons within the six months preceding or the twelve months following the change of control of the Company, Mr. Huseman would be entitled to a lump sum severance payment equal to three times the sum of his annual base salary plus the higher of (i) his current incentive target bonus for the full year in which the termination of employment occurred or (ii) the highest annual incentive bonus received by him for any of the last three fiscal years.

Basic has entered into employment agreements with various other executive officers through December 2012. Under these agreements, if the officer's employment is terminated for certain reasons, he would be entitled to a lump sum severance payment equal to either 0.75 times to 1.5 times the sum of his annual base salary plus his current annual incentive target bonus for the full year in which the termination occurred . If employment is terminated for certain reasons within the six months preceding or the twelve months following the chance of control of the Company, he would be entitled to a lump sum severance payment equal to either 1.0 or 2.0 times the sum of his annual base salary plus the higher of (i) his current incentive target bonus for the full year in which the termination of employment occurred or (ii) the highest annual incentive bonus received by him for any of the last three fiscal years.

Self-Insured Risk Accruals

Basic is self-insured up to retention limits as it relates to workers' compensation, general liability claims, and medical and dental coverage of its employees. Basic generally maintains no physical property damage coverage on its workover rig fleet, with the exception of certain of its 24-hour workover rigs and newly manufactured rigs. Basic has deductibles per occurrence for workers' compensation, general liability claims, and medical and dental coverage of $750,000, $750,000 and $250,000, respectively. Basic has lower deductibles per occurrence for automobile liability. Basic maintains accruals in the accompanying consolidated balance sheets related to self-insurance retentions by using third-party data and claims history. In 2011 and 2010, Basic classified the workers' compensation self-insured risk reserve between short-term and long-term, with $5.0 million and $4.0 million being allocated to short-term and $5.5 million and $4.9 million being allocated to long-term, respectively.

At December 31, 2011 and December 31, 2010, self-insured risk accruals totaled approximately $19.7 million, net of $1,000 receivable for medical and dental coverage, and $16.6 million, net of $164,000 receivable for medical and dental coverage, respectively.

8. Stockholders' Equity

Common Stock

At December 31, 2011 and 2010, Basic had 80,000,000 shares of Basic's common stock, par value $.01 per share, authorized.

In March 2008, the Compensation Committee of Basic's Board of Directors approved grants of performance-based stock awards to certain members of management. In March 2009, it was determined that 93,500 shares, or 100% of the target number of shares, were earned based on the Company's achievement of certain earnings per share growth and return on capital employed performance over the performance period from January 1, 2006 through December 31, 2008, as compared to other members of a defined peer group. These shares remain subject to vesting over a three-year period, with the first shares vesting on March 15, 2010.

In March 2009, Basic granted various employees 571,824 unvested shares of common stock which vest over a five-year period. Also, in March 2009, Basic granted the Chairman of the Board 4,000 shares of common stock which vested immediately in lieu of annual cash director fees.

In March 2009, the Compensation Committee of Basic's Board of Directors approved grants of performance-based stock awards to certain members of management. In March 2010, it was determined that 79,500 shares, or 30% of the target number of shares, were earned based on Basic's achievement of certain earnings per share growth and return on capital employed performance over the performance period from January 1, 2007 through December 31, 2009, as compared to other members of a defined peer group. These shares remain subject to vesting over a three-year period, with the first shares vesting on March 15, 2011.

In May 2009, consistent with its director compensation practices, Basic granted a new board member 37,500 shares of restricted common stock which vest over a three-year period.

In March 2010, Basic granted various employees 588,600 unvested shares of common stock which vest over a five-year period.

In March 2010, the Compensation Committee of Basic's Board of Directors approved grants of performance-based stock awards to certain members of management. In February 2011, it was determined that 285,281 shares, or 150% of the target number of shares, were earned based on Basic's achievement of total stockholder return over the performance period from January 1, 2010 through December 31, 2010, as compared to other members of a defined peer group. These shares remain subject to vesting over a three-year period, with the first shares vesting on March 15, 2012.

In March 2011, Basic granted various employees 510,399 restricted shares of common stock that vest over a three-year period.

During the year ended 2011, Basic issued 480,000 shares of common stock from treasury stock for the exercise of stock options and 136,000 shares of newly-issued common stock for the exercise of stock options.

Treasury Stock

On October 13, 2008, Basic announced that its Board of Directors authorized the repurchase of up to $50.0 million of Basic's shares of common stock from time to time in open market or private transactions, at Basic's discretion. The number of shares purchased and the timing of purchases is based on several factors, including the price of the common stock, general market conditions, available cash and alternative investment opportunities. In 2009, Basic repurchased 809,093 shares at a total price of $6.0 million (an average of $7.41 per share), inclusive of commissions and fees. The stock repurchase program was suspended by the Board of Directors during the first quarter of 2009.

Basic also acquired treasury shares through net share settlements for payment of payroll taxes upon the vesting of restricted stock. Basic repurchased a total of 79,730 and 40,381 shares through net share settlements during 2011 and 2010, respectively.

Preferred Stock

At December 31, 2011 and 2010, Basic had 5,000,000 shares of preferred stock, par value $.01 per share, authorized, of which none was designated, issued or outstanding.

9. Stockholders' Agreement

On December 20, 2010, Basic entered into the Third Amended and Restated Stockholders' Agreement (the "Stockholders' Agreement") effective as of December 20, 2010 by and among Basic and certain affiliates of DLJ Merchant Banking party thereto (such affiliates, the "DLJ Parties"), which amended and restated the Second Amended and Restated Stockholders' Agreement dated as of April 2, 2004, which terminated with respect to all other parties in accordance with its terms on December 21, 2010.

The Stockholders' Agreement provides for certain informational and consultation rights, along with confidentiality obligations, and registration rights for the DLJ Parties. As long as (i) any DLJ Party remains an Affiliate (as defined in the Stockholders' Agreement) of Basic or (ii) the DLJ Parties, collectively, beneficially hold at least ten percent of the outstanding shares of Basic's common stock, the DLJ Parties can require Basic to register shares of common stock on up to three occasions, provided that the proposed offering proceeds for the offering equal or exceed $10 million (or $5 million if Basic is able to register such securities on Form S-3). In addition such demand registration rights, the Stockholders' Agreement provides the DLJ Parties with piggyback registration rights with respect to any proposed offering of equity securities pursuant to a registration statement filed by Basic (other than a registration statement on Form S-4 or Form S-8). Basic is also obligated under the Stockholders' Agreement to perform certain other actions in connection with a demand registration or piggyback registration request by any of the DLJ Parties.

The Stockholders' Agreement terminates upon the earliest of (i) the dissolution, liquidation or winding-up of Basic, (ii) the date all of the DLJ Parties cease to be affiliates of Basic and the DLJ Parties, collectively, beneficially hold less than ten percent of the outstanding shares of common stock of Basic, or (iii) December 21, 2015.

10. Incentive Plan

In May 2003, Basic's board of directors and stockholders approved the Basic 2003 Incentive Plan (as amended effective May 26, 2009) (the "Plan"), which provides for granting of incentive awards in the form of stock options, restricted stock, performance awards, bonus shares, phantom shares, cash awards and other stock-based awards to officers, employees, directors and consultants of Basic. The Plan assumed the awards of the plans of Basic's predecessors that were awarded and remained outstanding prior to adoption of the Plan. The Plan provides for the issuance of 8,350,000 shares. Of these shares, approximately 2,356,941 shares are available for grant as of December 31, 2011. The Plan is administered by the Plan committee, and in the absence of a Plan committee, by the Board of Directors, which determines the awards and the associated terms of the awards and interprets its provisions and adopts policies for implementing the Plan. The number of shares authorized under the Plan and the number of shares subject to an award under the Plan will be adjusted for stock splits, stock dividends, recapitalizations, mergers and other changes affecting the capital stock of Basic.

There were no options granted during 2011, 2010 or 2009.

During the years ended December 31, 2011, 2010 and 2009, compensation expense related to share-based arrangements including both restricted stock awards and stock option awards was approximately $8.0 million, $5.7 million and $5.2 million, respectively. For compensation expense recognized during the years ended December 31, 2011, 2010 and 2009, Basic recognized a tax benefit of approximately $3.2 million, $2.1 million and $1.9 million, respectively.

As of December 31, 2011, there was $15.5 million of total unrecognized compensation related to non-vested share-based compensation arrangements granted under the Plan. That cost is expected to be recognized over a weighted-average period of 2.4 years. The total fair value of share-based awards vested during the years ended December 31, 2011, 2010 and 2009 was approximately $9.1 million, $3.9 million and $4.1 million, respectively. The actual tax benefit realized for the tax deduction from vested share-based awards was $619,000 and $201,000, respectively, for the years ended December 31, 2010 and 2009. During 2011 there was no tax benefit due to the NOL, if there was no NOL the tax benefit would have been $1.4 million.

Stock Option Awards

The fair value of each option award is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. Options granted under the Plan expire ten years from the date they are granted, and generally vest over a three-to-five year service period.

The following table reflects the summary of stock options outstanding at December 31, 2011 and the changes during the twelve months then ended:

	Number of Options Granted	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Instrinsic Value (000's)
Non-statutory stock options:				
Outstanding, beginning of period	1,414,450	$11.44		
Options granted	—	$ —		
Options forfeited	(5,000)	$ 6.98		
Options exercised	(616,000)	$ 7.36		
Options expired	(6,000)	$26.84		
Outstanding, end of period	787,450	$14.55	3.47	$5,988
Exercisable, end of period	764,450	$14.30	3.42	$5,988
Vested or expected to vest, end of period	787,450	$14.55	3.47	$5,988

The total intrinsic value of share options exercised during the years ended December 31, 2011, 2010 and 2009 was approximately $12.4 million, $393,000 and $15,000, respectively.

Cash received from option exercises under the Plan was approximately $4.5 million, $322,000 and $35,000 for the years ended December 31, 2011, 2010 and 2009, respectively. The actual tax benefit realized for the tax deductions from options exercised was $142,000 and $6,000, respectively, for the years ended December 31, 2010 and 2009. During 2011 there was no tax benefit due to the NOL, if there was no NOL the tax benefit would have been $3.7 million.

The Company has a history of issuing treasury and newly-issued shares to satisfy share option exercises.

Restricted Stock Awards

On March 10, 2011, the Compensation Committee of Basic's Board of Directors approved grants of performance-based stock awards to certain members of management. The performance-based awards are tied to Basic's achievement of total stockholder return over the performance period from January 1, 2011 through December 31, 2011, as compared to other members of a defined peer group. The number of shares to be issued will range from 0% to 150% of the 148,683 target number of shares depending on the performance noted above. Any shares earned at the end of the performance period will then remain subject to vesting over a three-year period, with the first shares vesting March 15, 2013. As of December 31, 2011, Basic estimated that 112.5% of the target number of performance-based awards will be earned.

A summary of the status of the Company's non-vested share grants at December 31, 2011 and changes during the year ended December 31, 2011 is presented in the following table:

Nonvested Shares	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Nonvested at beginning of period	1,802,573	$11.06
Granted during period	686,600	19.48
Vested during period	(343,785)	13.48
Forfeited during period	(183,217)	12.87
Nonvested at end of period	1,962,171	$13.41

11. Related Party Transactions

Basic had receivables from employees of approximately $65,000 and $42,000 as of December 31, 2011 and December 31, 2010, respectively. During 2006, Basic entered into a lease agreement with Darle Vuelta Cattle Co., LLC, an affiliate of the Chief Executive Officer, for approximately $69,000 per year. The term of the lease is five years and will continue on a year-to-year basis unless terminated by either party. In December 2010, Basic entered into a lease agreement with Darle Vuelta Cattle Co., LLC for the right to operate a salt water disposal well, brine well and fresh water well. The term of the leases is two years and will continue until the salt water disposal well and brine well are plugged and no fresh water is being sold. The lease payments are the greater of (i) the sum of $0.10 per barrel of disposed oil and gas waste and $0.05 per barrel of brine or fresh water sold or (ii) $5,000 per month. In October 2011, Basic purchased approximately 17 acres of land for approximately $209,000 from Darle Vuelta Cattle Co., LLC.

12. Profit Sharing Plan

Basic has a 401(k) profit sharing plan that covers substantially all employees. Employees may contribute up to their base salary not to exceed the annual Federal maximum allowed for such plans. Basic makes a matching contribution proportional to each employee's contribution. Employee contributions are fully vested at all times. Employer matching contributions vest incrementally, with full vesting occurring after five years of service. Employer contributions to the 401(k) plan approximated $2.6 million, $80,000, and $671,000 in 2011, 2010 and 2009, respectively.

13. Deferred Compensation Plan

In April 2005, Basic established a deferred compensation plan for certain employees. Participants may defer up to 50% of their salary and 100% of any cash bonuses. Basic makes matching contributions of 100% of the first 3% of the participants' deferred pay and 50% of the next 2% of the participants' deferred pay to a maximum match of $9,800 per year. Employer matching contributions and earnings thereon are subject to a five-year vesting schedule with full vesting occurring after five years of service. Employer contributions to the deferred compensation plan net of earnings approximated an expense of $128,000 in 2011, an expense of $337,000 in 2010 and an expense of $565,000 in 2009, respectively.

14. Earnings Per Share

Basic earnings per common share are determined by dividing net earnings applicable to common stock by the weighted average number of common shares actually outstanding during the year. Diluted earnings per common share is based on the increased number of shares that would be outstanding assuming conversion of dilutive outstanding securities using the "as if converted" method. The following table sets forth the computation of basic and diluted earnings per share (in thousands, except share data):

	Years ended December 31,		
	2011	2010	2009
Numerator (both basic and diluted):			
Net income available to common stockholders	$ 47,163	$ (43,563)	$ (253,538)
Denominator:			
Denominator for basic earnings per share	40,375,013	39,714,053	39,684,231
Stock options	382,436	—	—
Unvested restricted stock	779,180	—	—
Denominator for diluted earnings per share	41,536,629	39,714,053	39,684,231
Basic earnings per common share:			
Net income available to common stockholders	$ 1.17	$ (1.10)	$ (6.39)
Diluted earnings per common share:			
Net income available to common stockholders	$ 1.14	$ (1.10)	$ (6.39)

There were no antidiluvite shares at December 31, 2011. The number of antidilutive shares at December 31, 2010 and 2009 was 1.7 million and 1.4 million, respectively.

15. Business Segment Information

Basic's reportable business segments are Completion and Remedial Services, Fluid Services, Well Servicing, and Contract Drilling. These segments have been selected based on changes in management's resource allocation and performance assessment in making decisions regarding the Company. The following is a description of the segments:

Completion and Remedial Services: This segment utilizes a fleet of pressure pumping units, air compressor packages specially configured for underbalanced drilling operations, coiled tubing services, nitrogen services, water treatment, cased-hole wireline units, an array of specialized rental equipment and fishing tools, thru-tubing and snubbing units. The largest portion of this business consists of pressure pumping services focused on cementing, acidizing and fracturing services in niche markets.

Fluid Services: This segment utilizes a fleet of trucks and related assets, including specialized tank trucks, storage tanks, water wells, disposal facilities and related equipment. Basic employs these assets to provide, transport, store and dispose of a variety of fluids. These services are required in most workover, completion and remedial projects as well as part of daily producing well operations. Also included in this segment are our construction services which provide services for the construction and maintenance of oil and natural gas production infrastructures.

Well Servicing: This 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. Basic's well servicing equipment and capabilities also facilitate most other services performed on a well. This segment also includes the manufacture and servicing of mobile well servicing rigs.

Contract Drilling: This segment utilizes shallow and medium depth rigs and associated equipment for drilling wells to a specified depth for customers on a contract basis.

Basic's management evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general corporate expenses associated with managing all reportable operating segments. Corporate assets consist principally of working capital and debt financing costs.

The following table sets forth certain financial information with respect to Basic's reportable segments (in thousands):

	Completion and Remedial Services	Fluid Services	Well Servicing	Contract Drilling	Corporate and Other	Total
Year ended December 31, 2011						
Operating revenues	$ 537,134	$ 332,010	$ 333,057	$ 41,054	$ —	$1,243,255
Direct operating costs	(297,276)	(211,959)	(228,723)	(28,154)	—	$ (766,112)
Segment profits	$ 239,858	$ 120,051	$ 104,334	$ 12,900	$ —	$ 477,143
Depreciation and amortization	$ 45,651	$ 42,612	$ 48,016	$ 9,994	$ 8,068	$ 154,341
Capital expenditures, (excluding acquisitions)	$ 57,928	$ 51,543	$ 46,805	$ 53,112	$ 12,451	$ 221,839
Identifiable assets	$ 398,664	$ 241,720	$ 280,992	$ 77,402	$461,150	$1,459,928
Year ended December 31, 2010						
Operating revenues	$ 261,436	$ 241,164	$ 204,872	$ 20,767	$ —	$ 728,239
Direct operating costs	(156,573)	(178,152)	(156,885)	(15,250)	—	$ (506,860)
Segment profits	$ 104,863	$ 63,012	$ 47,987	$ 5,517	$ —	$ 221,379
Depreciation and amortization	$ 33,538	$ 38,745	$ 50,530	$ 5,171	$ 7,017	$ 135,001
Capital expenditures, (excluding acquisitions)	$ 15,795	$ 18,247	$ 23,797	$ 2,435	$ 3,305	$ 63,579
Identifiable assets	$ 215,503	$ 185,057	$ 248,441	$ 28,375	$352,437	$1,029,813
Year ended December 31, 2009						
Operating revenues	$ 134,818	$ 214,822	$ 160,614	$ 16,373	$ —	$ 526,627
Direct operating costs	(95,287)	(159,079)	(121,618)	(13,604)	—	$ (389,588)
Segment profits	$ 39,531	$ 55,743	$ 38,996	$ 2,769	$ —	$ 137,039
Depreciation and amortization	$ 31,313	$ 37,594	$ 49,005	$ 7,237	$ 7,371	$ 132,520
Capital expenditures, (excluding acquisitions)	$ 10,247	$ 12,303	$ 16,037	$ 2,368	$ 2,412	$ 43,367
Identifiable assets	$ 194,988	$ 195,107	$ 244,556	$ 41,320	$363,570	$1,039,541

The following table reconciles the segment profits reported above to the operating income as reported in the consolidated statements of operations (in thousands):

	Year ended December 31,		
	2011	2010	2009
Segment profits	$ 477,143	$ 221,379	$ 137,039
General and administrative expenses	(142,264)	(107,781)	(104,253)
Depreciation and amortization	(154,341)	(135,001)	(132,520)
Gain (loss) on disposal of assets	(447)	(2,856)	(2,650)
Goodwill impairment	—	—	(204,014)
Operating income (loss)	$ 180,091	$ (24,259)	$(306,398)

16. Accrued Expenses

The accrued expenses are as follows (in thousands):

	December 31, 2011	December 31, 2010
Compensation related	$27,068	$20,936
Workers' compensation self-insured risk reserve	4,967	3,968
Health self-insured risk reserve	3,928	4,374
Authority for expenditure accrual	379	141
Ad valorem taxes	5	171
Sales tax	2,590	1,343
Insurance obligations	6,174	3,576
Purchase order accrual	—	39
Professional fee accrual	497	564
Contingent earnout obligation	345	346
Fuel accrual	1,432	1,415
Accrued interest	17,711	14,364
	$65,096	$51,237

17. Supplemental Schedule of Cash Flow Information

The following table reflects non-cash financing and investing activity during:

	Year ended December 31, 2011	2010	2009
		(In thousands)	
Capital leases issued for equipment	$57,693	$23,363	$18,594
Asset retirement obligation additions	$ 53	$ 67	$ 149

Basic paid $990,000 in income taxes during the year ended December 31, 2011 and paid no income taxes during the year ended December 31, 2010. Basic paid approximately $2.3 million in income taxes during the year ended December 31, 2009.

18. Quarterly Financial Data (Unaudited)

The following table summarizes results for each of the four quarters in the years ended December 31, 2011 and 2010 (in thousands, except earnings per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year ended December 31, 2011:					
Total revenues	$246,054	$296,855	$345,987	$354,359	$1,243,255
Segment profits	$ 89,968	$111,538	$136,647	$138,990	$ 477,143
Income from continuing operations	$(18,493)	$ 16,550	$ 26,595	$ 22,511	$ 47,163
Net income available to common stockholders	$(18,493)	$ 16,550	$ 26,595	$ 22,511	$ 47,163
Basic earnings per share of common stock(a):					
Net income available to common stockholders	$ (0.46)	$ 0.41	$ 0.66	$ 0.55	$ 1.17
Diluted earnings per share of common stock(a):					
Net income (loss) available to common stockholders	$ (0.46)	$ 0.40	$ 0.64	$ 0.54	$ 1.14
Weighted average common shares outstanding:					
Basic	39,884	40,356	40,451	40,658	40,375
Diluted	39,884	41,336	41,396	41,307	41,537
Year ended December 31, 2010:					
Total revenues	$142,966	$175,132	$197,261	$212,880	$ 728,239
Segment profits	$ 36,933	$ 53,588	$ 59,051	$ 71,807	$ 221,379
Income from continuing operations	$(21,591)	$(10,672)	$ (9,332)	$ (1,968)	$ (43,563)
Net income available to common stockholders	$(21,591)	$(10,672)	$ (9,332)	$ (1,968)	$ (43,563)
Basic earnings per share of common stock(a):					
Net income available to common stockholders	$ (0.54)	$ (0.27)	$ (0.23)	$ (0.05)	$ (1.10)
Diluted earnings per share of common stock(a):					
Net income (loss) available to common stockholders	$ (0.54)	$ (0.27)	$ (0.23)	$ (0.05)	$ (1.10)
Weighted average common shares outstanding:					
Basic	39,621	39,724	39,743	39,776	39,714
Diluted	39,621	39,724	39,743	39,776	39,714

(a) The sum of individual quarterly net income per share may not agree to the total for the year due to each period's computation being based on the weighted average number of common shares outstanding during each period.

19. Fair Value Measurements

Fair value is the price that would be received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market based measurement considered from the perspective of a market participant. The Company uses market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. If observable prices or inputs are not available, unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued. The Company primarily applies a market approach for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

There is a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The Company classifies fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices in active markets for identical assets or liabilities that the Company has the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured.

Level 3 — Inputs reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

In valuing certain assets and liabilities, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

The Company's asset retirement obligation related to its salt water disposal sites, brine water wells, gravel pits and land farm sites, each of which is subject to rules and regulations regarding usage and eventual closure, is measured using primarily Level 3 inputs. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, inflation rate and well life. The inputs are calculated based on historical data as well as current estimated costs.

The fair value is calculated by taking the present value of the expected cash flow at the time of the closure of the site. The following table reflects the changes in the liability during years ended December 31, 2011 and 2010 (in thousands):

Balance, December 31, 2009	$1,969
Additional asset retirement obligations recognized through acquisitions	45
Accretion expense	162
Settlements	(81)
Adjustment for change in estimate	(112)
Balance, December 31, 2010	$1,983
Additional asset retirement obligations recognized through acquisitions	53
Accretion expense	124
Settlements	(315)
Balance, December 31, 2011	$1,845

20. Subsequent Events

On January 13, 2012, Basic acquired substantially all of the operating assets of Mayo Marrs Casing Pulling, Inc., MMCP Leasing, LTD. and MMCP Equipment, LTD. for approximately $6.6 million.

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses(a)	Additions: Charged to Other Accounts(b)	Deductions(c)	Balance at End of Period
			(in thousands)		
Year Ended December 31, 2011					
Allowance for Bad Debt	$3,078	$(1,171)	$—	$ (677)	$1,230
Year Ended December 31, 2010					
Allowance for Bad Debt	$4,757	$ 352	$—	$(2,031)	$3,078
Year Ended December 31, 2009					
Allowance for Bad Debt	$5,838	$ 1,917	$—	$(2,998)	$4,757

(a) Charges relate to provisions for doubtful accounts

(b) Reflects the impact of acquisitions

(c) Deductions relate to the write-off of accounts receivable deemed uncollectible

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Disclosure Controls and Procedures

Based on their evaluation as of the end of the fiscal year ended December 31, 2011, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are effective to ensure that information required to be disclosed in reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and effective to ensure that information required to be disclosed in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the most recent fiscal quarter, there have been no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Design and Evaluation of Internal Control over Financial Reporting

Management's Report on Internal Control over Financial Reporting and the Report of the Independent Registered Public Accounting Firm are set forth in Part II, Item 8 of this report and are incorporated herein by reference.

ITEM 9B. *OTHER INFORMATION*

None.

PART III

Pursuant to paragraph 3 of General Instruction G to Form 10-K, the information required by Item 10, to the extent not set forth below in this Part III, and Items 11 through 14 of Part III of this Report is incorporated by reference from our definitive proxy statement involving the election of directors and the approval of independent auditors, which is to be filed pursuant to Regulation 14A within 120 days after the end of our fiscal year ended December 31, 2011.

Executive Officers of the Registrant

Our executive officers as of December 31, 2011 and their respective ages and positions are as follows:

Name	Age	Position
Kenneth V. Huseman	59	President, Chief Executive Officer and Director
Alan Krenek	56	Senior Vice President, Chief Financial Officer, Treasurer and Secretary
T.M. "Roe" Patterson	37	Senior Vice President and Chief Operating Officer
James F. Newman	47	Group Vice President — Permian Business Unit
Douglas B. Rogers	48	Vice President — Marketing
James E. Tyner	61	Vice President — Human Resources

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

Kenneth V. Huseman (President — Chief Executive Officer and Director) has 33 years of well servicing experience. He has been our President and Chief Executive Officer and a Director since 1999. Prior to joining Basic, he was Chief Operating Officer at Key Energy Services from 1996 to 1999. He was a Divisional Vice President at WellTech, Inc., from 1993 to 1996. From 1978 to 1993, he was employed at Pool Energy Services Co., where he managed operations throughout the United States. Mr. Huseman graduated with a B.B.A. degree in Accounting from Texas Tech University.

Alan Krenek (Senior Vice President, Chief Financial Officer, Treasurer and Secretary) has 24 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.

T. M. "Roe" Patterson (Senior Vice President and Chief Operating Officer) has 17 years of related industry experience. He has been our Senior Vice President and Chief Operating Officer since April 2011, and has been a Senior Vice President since September 2008 and the Vice President of various different groups within Basic since February 2006. Prior to joining us, 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.

James F. Newman (Group Vice President — Permian Business Unit) has 27 years of related industry experience and has been our Group Vice President — Permian Business Unit since April 2011 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.

Douglas B. Rogers (Vice President — Marketing) has 29 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.

PART IV

ITEM 15. *EXHIBITS, FINANCIAL STATEMENT SCHEDULES*

(a) Financial Statements, Schedules and Exhibits

(1) Financial Statements — Basic Energy Services, Inc. and Subsidiaries:

The Financial Statements listed in the Index to Consolidated Financial Statements are filed as part of this report on Form 10-K (*see* Part II, Item 8, *Financial Statements and Supplementary Data*).

(2) Financial Statement Schedules

With the exception of Schedule II — Valuation and Qualifying Accounts, all other consolidated financial statement schedules have been omitted because they are not required, are not applicable, or the required information has been included elsewhere within this Form 10-K.

(3) Exhibits

Exhibit No.	Description
2.1*	Agreement and Plan of Merger, dated as of January 8, 2007, by and among Basic Energy Services, Inc., JS Acquisition LLC and JetStar Consolidated Holdings, Inc. (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on March 8, 2007)
2.2*	Amendment to Merger Agreement, dated as of March 5, 2007, by and among Basic Energy Services, Inc., JS Acquisition LLC and JetStar Consolidated Holdings, Inc. (Incorporated by reference to Exhibit 2.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on March 8, 2007)
3.1*	Amended and Restated Certificate of Incorporation of Basic Energy Services, Inc., dated September 22, 2005. (Incorporated by reference to Exhibit 3.1 of the Company's Registration Statement on Form S-1 (SEC File No. 333-127517), filed on September 28, 2005)
3.2*	Amended and Restated Bylaws of Basic Energy Services, Inc., effective as of March 9, 2010. (Incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on March 15, 2010)
4.1*	Specimen Stock Certificate representing common stock of Basic Energy Services, Inc. (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1 (SEC File No. 333-127517), filed on November 4, 2005)
4.2*	Indenture dated April 12, 2006, among Basic Energy Services, Inc., the Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on April 13, 2006)
4.3*	Form of 7.125% Senior Note due 2016. (Included in the Indenture filed as Exhibit 4.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on April 13, 2006)
4.4*	First Supplemental Indenture dated as of July 14, 2006 to Indenture dated as of April 12, 2006 among Basic Energy Services, Inc. as Issuer, the Subsidiary Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on July 20, 2006)
4.5*	Second Supplemental Indenture dated as of April 26, 2007 and effective as of March 7, 2007 to Indenture dated as of April 12, 2006 among Basic Energy Services, Inc. as Issuer, the Subsidiary Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on May 1, 2007)

Exhibit No.	Description
4.6*	Third Supplemental Indenture dated as of April 26, 2007 to Indenture dated as of April 12, 2006 among Basic Energy Services, Inc. as Issuer, the Subsidiary Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on May 1, 2007)
4.7*	Fourth Supplemental Indenture dated as of February 9, 2009 to Indenture dated as of April 12, 2006 among Basic Energy Services, Inc. as Issuer, the Subsidiary Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.7 of the Company's Annual Report on Form 10-K (SEC File No. 001-32693), filed on March 9, 2009)
4.8*	Fifth Supplemental Indenture dated as of July 23, 2009 to Indenture dated as of April 12, 2006 among Basic Energy Services, Inc. as Issuer, the Subsidiary Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.8 of the Company's Annual Report on Form 10-K (SEC File No. 001-32693), filed on March 1, 2010)
4.9*	Sixth Supplemental Indenture dated as of December 22, 2010 to Indenture dated as of April 12, 2006, by and among Basic Energy Services, Inc. as Issuer, the Subsidiary Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on December 22, 2010)
4.10*	Seventh Supplemental Indenture dated as of August 5, 2011 to Indenture dated as of April 12, 2006, by and among Basic Energy Services, Inc. as Issuer, the Subsidiary Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on August 10,2011)
4.11*	Indenture dated as of February 15, 2011, among Basic Energy Services, Inc. as Issuer, the Guarantors named therein and Wells Fargo Bank, N.A., as trustee. (Incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on February 18, 2011)
4.12*	Form of 7.75% Senior Note due 2019. (Included as Exhibit A to Exhibit 4.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on February 18, 2011)
4.13*	First Supplemental Indenture dated as of August 5, 2011 to Indenture dated as of February 15, 2011 among Basic Energy Services, Inc. as Issuer, the Subsidiary Guarantors named therein and Wells Fargo Bank, N.A., as trustee. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on August 10, 2011)
10.1*†	Form of Indemnification Agreement. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on March 15, 2010)
10.2*	Third Amended and Restated Stockholders' Agreement entered into effective as of December 20, 2010, by and among Basic Energy Services, Inc., DLJMB Funding III, Inc., DLJ ESC II, L.P., DLJ Offshore Partners III, C.V., DLJ MB Partners III GmbH & Co., KG, DLJ Merchant Banking Partners III, L.P., DLJ Offshore Partners III, C.V., DLJ Offshore Partners III-1, C.V., DLJ Offshore Partners III-2, C.V., Millennium Partners II, L.P., and MBP Plan Investors, L.P. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on December 22, 2010)
10.3*	Credit Agreement dated as of September 28, 2010, among Basic Energy Services, Inc., the Subsidiary Guarantors party thereto, the Lenders party thereto and Capital One, National Association, as administrative agent, collateral agent and issuing bank. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on October 4, 2010)

Exhibit No.	Description
10.4*	Security Agreement dated as of September 28, 2010, among Basic Energy Services, Inc. and the other Debtors party thereto in favor of Capital One, National Association, as collateral agent. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on October 4, 2010)
10.5*	Supplement No. 1 dated as of December 22, 2010 to Security Agreement dated as of September 28, 2010 among Basic Energy Services, Inc. and the other Debtors party thereto in favor of Capital One, National Association, as collateral agent. (Incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on December 22, 2010)
10.6*	Credit Agreement dated as of February 15, 2011, among Basic Energy Services, Inc. as Borrower, each lender from time to time party thereto and Bank of America, N.A., as administrative agent, a swing line lender and l/c issuer. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on February 18, 2011)
10.7*	Amendment No. 1 to Credit Agreement, dated as of June 7, 2011, by and among Basic as Borrower, the lenders party thereto and Bank of America, N.A., as administrative agent, a swing line lender and l/c issuer. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on June 7, 2011)
10.8*	Amendment No. 2 to Credit Agreement, dated as of July 15, 2011, by and among Basic as Borrower, the lenders party thereto and Bank of America, N.A., as administrative agent, a swing line lender and l/c issuer. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on July 21, 2011)
10.9*	Security Agreement dated as of February 15, 2011, by and among Basic Energy Services, Inc. as Borrower and the Debtors party thereto in favor of Bank of America, N.A., as administrative agent. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on February 18, 2011)
10.10*	Supplement No. 1 dated as of August 5, 2011 to Security Agreement dated as of February 15, 2011, by and among Basic Energy Services, Inc. as Borrower and the Debtors party thereto in favor of Bank of America, N.A., as administrative agent. (Incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on August 10, 2011)
10.11*†	Fourth Amended and Restated Basic Energy Services, Inc. 2003 Incentive Plan. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on June 1, 2009)
10.12*†	First Amendment to Fourth Amended and Restated Basic Energy Services, Inc. 2003 Incentive Plan. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K/A (SEC File No. 001-32693), filed on June 1, 2011)
10.13*†	Form of Non-Qualified Option Grant Agreement (Executive Officer — Pre-March 1, 2005). (Incorporated by reference to Exhibit 10.12 of the Company's Registration Statement on Form S-1 (SEC File No. 333-127517), filed on September 28, 2005)
10.14*†	Form of Non-Qualified Option Grant Agreement (Executive Officer — Post-March 1, 2005). (Incorporated by reference to Exhibit 10.13 of the Company's Registration Statement on Form S-1 (SEC File No. 333-127517), filed on September 28, 2005)
10.15*†	Form of Non-Qualified Option Grant Agreement (Non-Employee Director — Pre-March 1, 2005). (Incorporated by reference to Exhibit 10.14 of the Company's Registration Statement on Form S-1 (SEC File No. 333-127517), filed on September 28, 2005)

Exhibit No.	Description
10.16*†	Form of Non-Qualified Option Grant Agreement (Non-Employee Director — Post-March 1, 2005). (Incorporated by reference to Exhibit 10.15 of the Company's Registration Statement on Form S-1 (SEC File No. 333-127517), filed on September 28, 2005)
10.17*†	Form of Amendment to Nonqualified Stock Option Agreement, dated as of December 31, 2005, by and between Basic Energy Services, Inc. and the optionees party thereto. (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on January 4, 2006)
10.18*†	Form of Nonqualified Stock Option Agreement (Director form effective March 2006). (Incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K (SEC File No. 001-32693), filed on March 7, 2008)
10.19*†	Form of Nonqualified Stock Option Agreement (Employee form effective March 2006). (Incorporated by reference to Exhibit 10.14 of the Company's Annual Report on Form 10-K (SEC File No. 001-32693), filed on March 7, 2008)
10.20*†	Form of Restricted Stock Grant Agreement (Officers and Employees — Post-March 1, 2007). (Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001- 32693), filed on May 10, 2007)
10.21*†	Form of Restricted Stock Grant Agreement (Non-Employee Directors — Post-March 1, 2007). (Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-32693), filed on May 10, 2007)
10.22*†	Form of Non-Qualified Stock Option Grant Agreement (Post-March 1, 2007). (Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (SEC File No. 001-32693), filed on May 10, 2007)
10.23*†	Form of Performance-Based Award Agreement (Officers and Employees). (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on March 17, 2008)
10.24*†	Form of Restricted Stock Grant Agreement (Officers and Employees). (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q (SEC File No. 001-32693), filed on May 8, 2008)
10.25*†	Form of Restricted Stock Grant Agreement (Non-Employee Directors). (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q (SEC File No. 001-32693), filed on May 8, 2008)
10.26*†	Form of Performance-Based Award Agreement (Officers and Employees) (effective March 2009). (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32963), filed on March 19, 2009)
10.27*†	Form of Performance-Based Award Agreement (Officers and Employees) (effective March 2010). (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on March 15, 2010)
10.28*†	Form of Performance-Based Award Agreement for Performance Year 2011 (Officers and Employees) (effective March 2011). (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on March 16, 2011)
10.29*†	Employment Agreement of Kenneth V. Huseman, effective as of December 31, 2006. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on January 4, 2007)

Exhibit No.	Description
10.30*†	Employment Agreement of Alan Krenek, effective as of December 31, 2006. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on January 4, 2007)
10.31*†	Employment Agreement of James E. Tyner, effective as of December 31, 2006. (Incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on January 4, 2007)
10.32*†	Amended and Restated Employment Agreement of Thomas Monroe Patterson, effective as of November 21, 2008. (Incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on November 24, 2008)
10.33*†	First Amendment to Employment Agreement of Kenneth V. Huseman, effective as of January 23, 2007. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on January 29, 2007)
10.34*†	Amended and Restated Employment Agreement of James F. Newman, effective as of November 24, 2008. (Incorporated by reference to Exhibit 10.27 of the Company's Annual Report on Form 10-K (SEC File No. 001-32693), filed on February 26, 2010)
10.35*†	Employment Agreement of Douglas B. Rogers, effective as of March 16, 2009. (Incorporated by reference to Exhibit 10.28 of the Company's Annual Report on Form 10-K (SEC File No. 001-32693), filed on February 26, 2010)
10.36*	Purchase and Sale Agreement dated as of July 6, 2011, by and among Maverick Stimulation Company, LLC, Maverick Coil Tubing Services, LLC, MCM Holdings, LLC, Maverick Thru-Tubing Services, LLC, The Maverick Companies, LLC, Maverick Solutions, LLC, MSM Leasing, LLC and the sellers listed therein and Basic Energy Services, L.P. (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (SEC File No. 001-32693), filed on July 12, 2011)
12.1	Ratio of Earnings to Fixed Charges.
21.1*	Subsidiaries of the Company. (Incorporated by reference to Exhibit 21.1 of the Company's Registration Statement on Form S-4 (SEC File No. 333-176739), filed on September 8, 2011)
23.1	Consent of KPMG LLP
31.1	Certification by Chief Executive Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
31.2	Certification by Chief Financial Officer required by Rule 13a-14(a) and 15d-14(a) under the Exchange Act
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Incorporated by reference

† Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BASIC ENERGY SERVICES, INC.

By: /s/ Kenneth V. Huseman
Name: Kenneth V. Huseman
Title: *President, Chief Executive Officer and Director*

Date: February 24, 2012

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

Signature	Title	Date
/s/ Kenneth V. Huseman Kenneth V. Huseman	President, Chief Executive Officer and Director (Principal Executive Officer)	February 24, 2012
/s/ Alan Krenek Alan Krenek	Senior Vice President, Chief Financial Officer, Treasurer and Secretary (Principal Financial Officer and Principal Accounting Officer)	February 24, 2012
/s/ Steven A. Webster Steven A. Webster	Chairman of the Board	February 24, 2012
/s/ James S. D'Agostino, Jr. James S. D'Agostino, Jr.	Director	February 24, 2012
/s/ William E. Chiles William E. Chiles	Director	February 24, 2012
/s/ Robert F. Fulton Robert F. Fulton	Director	February 24, 2012
/s/ Sylvester P. Johnson, IV Sylvester P. Johnson, IV	Director	February 24, 2012
/s/ Antonio O. Garza, Jr. Antonio O. Garza, Jr.	Director	February 24, 2012
/s/ Thomas P. Moore, Jr. Thomas P. Moore, Jr.	Director	February 24, 2012

BOARD OF DIRECTORS

Kenneth V. Huseman
President, Chief Executive Officer and Director

Steven A. Webster
Chairman of the Board

William E. Chiles [1,3]
Director

James S. D'Agostino, Jr. [1,3]
Director

Robert F. Fulton [2]
Director

Sylvester P. Johnson, IV [2]
Director

Antonio O. Garza, Jr. [3]
Director

Thomas P. Moore, Jr. [1,2]
Director

[1] Audit Committee
[2] Nominating and Corporate Governance Committee
[3] Compensation Committee

EXECUTIVE MANAGEMENT

Kenneth V. Huseman
President, Chief Executive Officer and Director

Alan Krenek
Senior Vice President, Chief Financial Officer, Treasurer and Secretary

T. M. "Roe" Patterson
Senior Vice President, Chief Operating Officer

James F. Newman
Group Vice President, Permian Business Unit

Jim Tyner
Vice President, Human Resources

Doug Rogers
Vice President, Corporate Marketing

Cody Bissett
Vice President, Controller and Chief Accounting Officer

Tim Dame
Vice President, Pumping & Wireline Services Division

Trampas Poldrack
Vice President, Safety and Operations Support

SENIOR MANAGEMENT

Roger Massey
Vice President, Ark-La-Tex Region

Lynn Wigington
Vice President, Permian Business Unit, Rig and Truck Operations

Charles W. Swift
Vice President, Gulf Coast Region

Jerry Tufly
Vice President, Rocky Mountain Region

Randy Franklin
Vice President, Mid Continent Region

Bobby Adkins
Vice President, Downhole Services Support

Ron Scandolari
Vice President, Drilling

Mark D. Rankin
Vice President, Risk Management

Charles McIntyre
Vice President, Information Technology

CORPORATE OFFICE

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Alan Krenek
Chief Financial Officer
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alan.krenek@basicenergyservices.com

TRANSFER AGENT

American Stock Transfer & Trust Company
New York, New York

INDEPENDENT ACCOUNTANTS

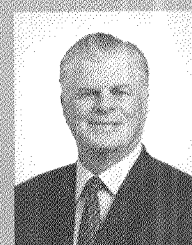
KPMG LLP
Dallas, Texas

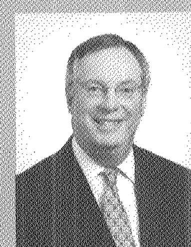
COUNSEL

Andrews Kurth LLP
Houston, Texas

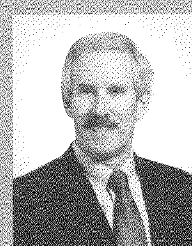

Kenneth V. Huseman


Steven A. Webster

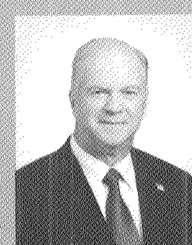

William E. Chiles


James S. D'Agostino, Jr.


Robert F. Fulton


Sylvester P. Johnson, IV


Antonio O. Garza, Jr.


Thomas P. Moore, Jr.

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ENERGY SERVICES

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