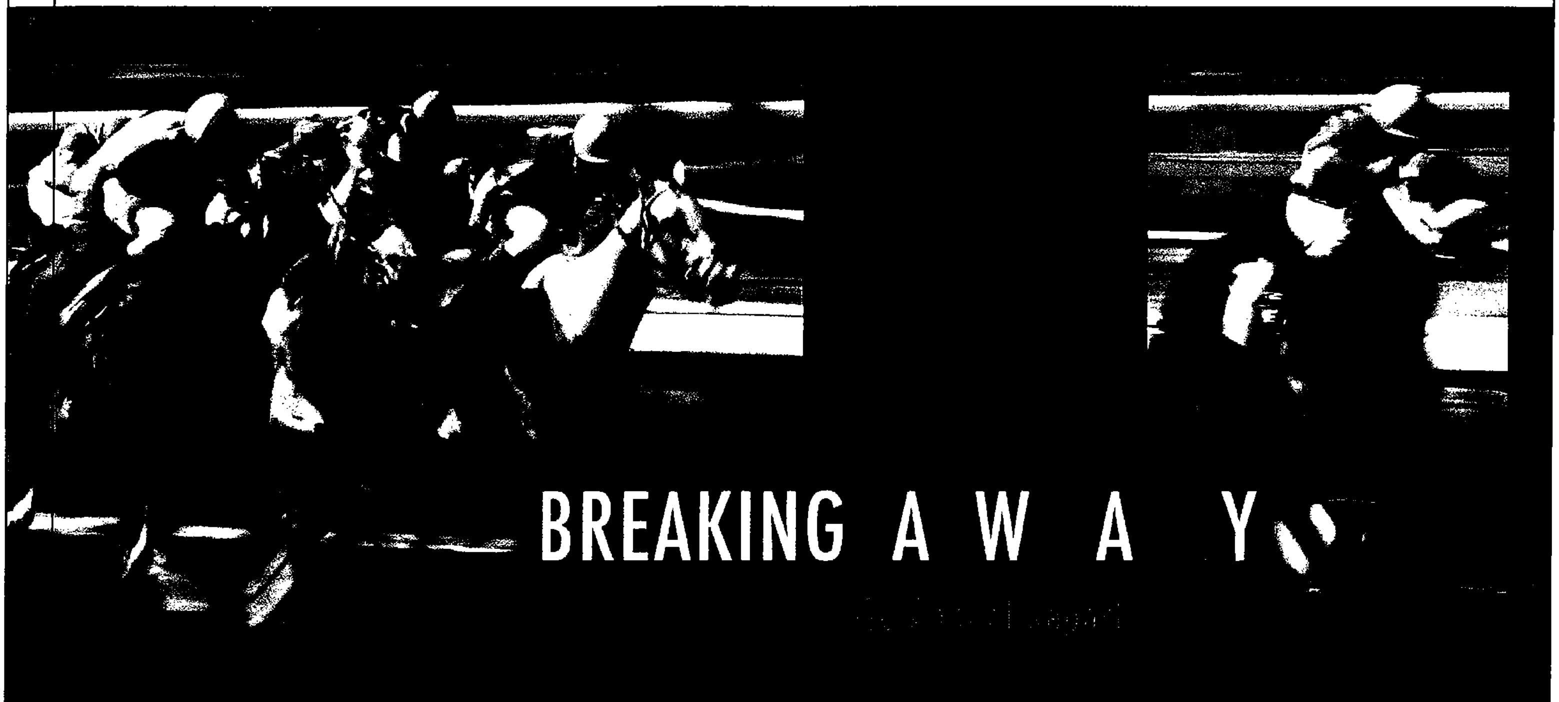


BREAKING AWAY

Complete
Production Services


FOCUS
Bakken
Core Operating Areas

CORPORATE PROFILE

Complete Production Services is one of North America's leading oilfield service providers, offering a complementary suite of applications focused on the completion and production phases in the life of a well. America's top oil and gas producers turn to us for innovative, basin-specific solutions that allow them to achieve maximum output from new completions and extend the life of aging wells.

With more than 6,500 employees working in the most active resource plays in North America, our success is based on a solid foundation of knowledge — both of the North American marketplace and the local resource plays in which we operate.

FINANCIAL and OPERATING HIGHLIGHTS

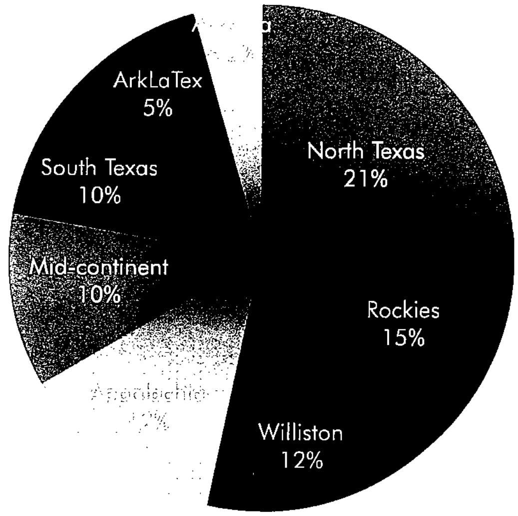
In $ thousands, except per share data in $

YEAR ENDED DECEMBER 31	2006	2007	2008	2009	2010
Revenue:					
Completion and production services	$ 860,508	$ 1,238,126	$1,541,709	$ 897,584	$ 1,354,797
Drilling services	194,517	212,272	234,104	114,729	172,821
Product sales	29,586	40,857	59,102	44,081	33,775
Total	$ 1,084,611	$ 1,491,255	$1,834,915	$ 1,056,394	$ 1,561,393
Modified EBITDA[1]	$ 309,743	$ 436,177	$ 500,227	$ 163,407	$ 374,908
Operating income (loss) from continuing operations	234,011	291,684	47,024	(187,412)	193,085
Operating income (loss) from continuing operations (excluding impairment loss)	234,011	304,778	319,030	(51,123)	193,085
Net income (loss) from continuing operations (excluding impairment loss)	124,448	159,511	168,267	(57,969)	84,158
Diluted earnings (loss) per share from continuing operations (excluding impairment loss)[1,2]	$ 1.83	$ 2.17	$ 2.26	$ (0.77)	$ 1.08
Diluted earnings (loss) per share from continuing operations	$ 1.83	$ 2.00	$ (1.15)	$ (2.42)	$ 1.08
Cash and cash equivalents	$ 19,766	$ 13,034	$ 18,500	$ 77,360	$ 126,681
Net property, plant and equipment	752,648	1,013,539	1,166,686	941,133	956,028
Total assets	1,739,198	2,050,633	1,987,353	1,588,854	1,800,576
Long-term debt, excluding current portion	750,311	825,985	843,842	650,002	650,000
Total shareholders' equity	$ 734,633	$ 926,031	$ 860,711	$ 698,890	$ 805,834

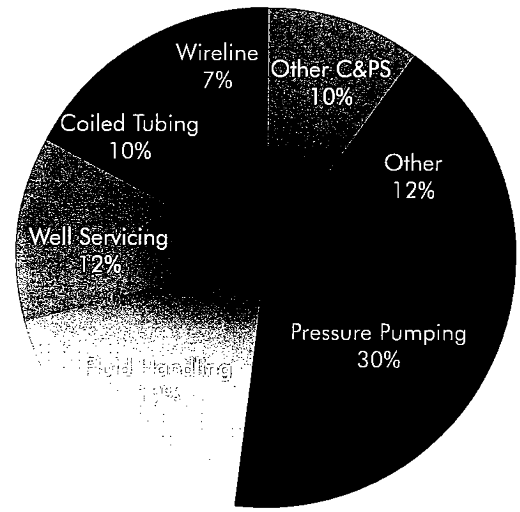
[1] See "Reconciliation of Modified EBITDA to Adjusted EBITDA and Net Income (Loss)" included on page 121 of this report.
[2] See "Reconciliation of Earnings Per Share Less Impairment Charge to Earnings Per Share (Loss)" included on page 122 of this report.

BALANCE

REVENUE BY SERVICE LINE[1]

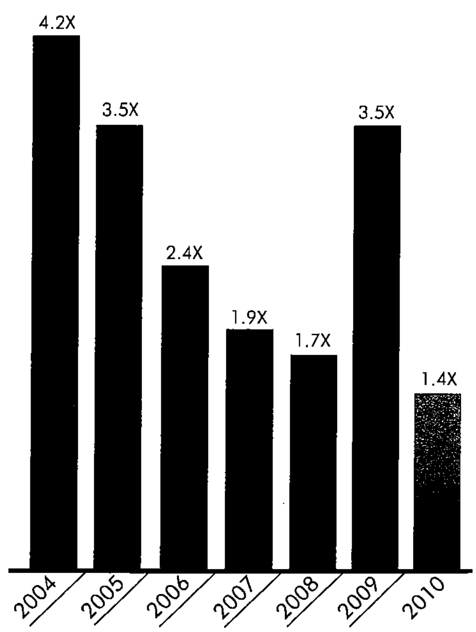


REVENUE BY REGION[1]

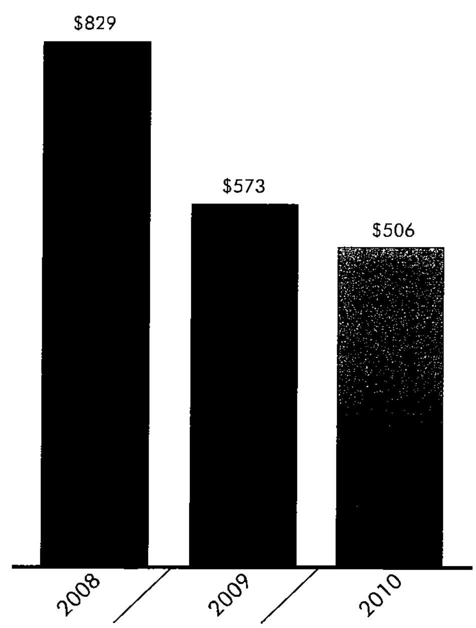


DISCIPLINE

LEVERAGE RATIO[2]



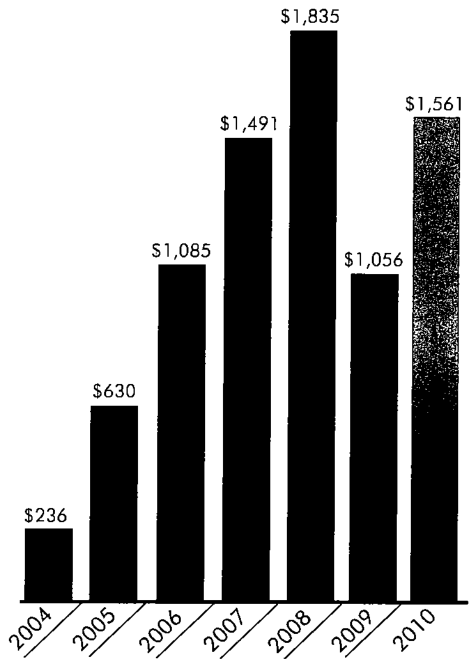
NET DEBT ($MMs)[3]



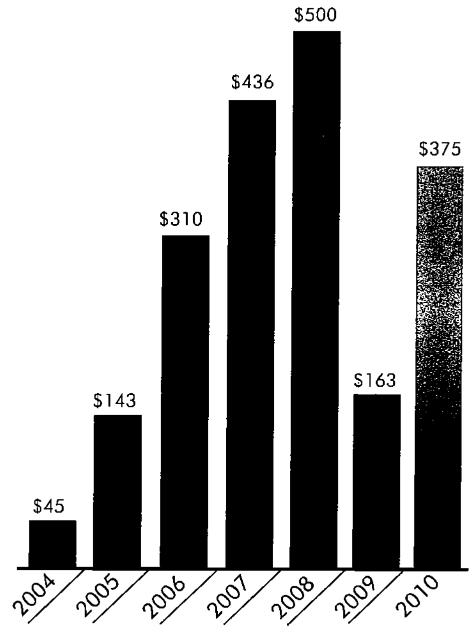
[1] For the quarter ended December 31, 2010.
[2] Net debt divided by Modified EBITDA excluding discontinued operations. See "Reconciliation of Modified EBITDA to Adjusted EBITDA and Net Income (Loss)" included on page 121 of this report.
[3] Net debt consists of long term debt minus cash and cash equivalents and restricted cash.

EXECUTION

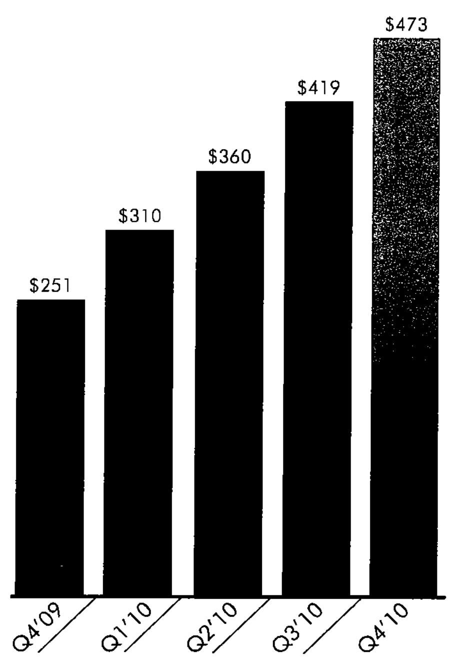
REVENUE BY YEAR ($MMs)



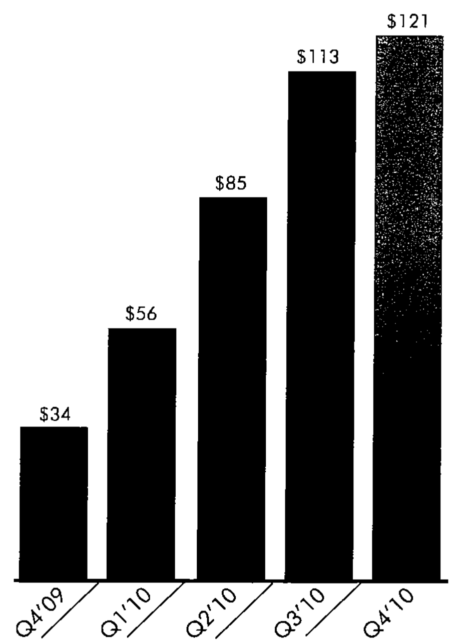
MODIFIED EBITDA BY YEAR ($MMs)[1]



REVENUE BY QUARTER ($MMs)



MODIFIED EBITDA BY QUARTER ($MMs)[1]



[1] See "Reconciliation of Modified EBITDA and Adjusted EBITDA and Net Income (Loss)" included on page 121 of this report.

TO OUR SHAREHOLDERS

I am pleased to report that Complete Production Services, Inc. had an excellent year in 2010. Revenue increased 48% to $1,561 million and Modified EBITDA increased by 129% or $212 million. Our achievements were accomplished from the hard work and dedication of our loyal employees as they executed our balanced and focused business strategy that positioned us to capitalize on a growing market.

Our customers significantly increased their activity levels in 2010. Higher oil prices and renewed access to capital resulted in improved cash flow and stronger balance sheets which provided our customers with the confidence to aggressively increase their levels of spending. The average U.S. rig count increased 42% in 2010, led by an 80% increase in the horizontal rig count, which represents the service-intensive resource plays. The rising rig counts primarily reflect increased activity in the emerging oil and liquid-rich resource plays. The industry is focused on these plays because recent advances in well completion techniques and technologies have enabled more favorable economic extraction of these hydrocarbons from unconventional resource plays. Consequently, oil and liquid-rich resource plays are transforming the North American market from one that was previously more focused on natural gas activity.

Complete's success in 2010 was the result of the actions taken by our team in anticipation of a market recovery, which included:

- Protecting our existing positions and expanding our presence into basins which we believed would see the strongest recovery; and
- Solidifying and enhancing key customer relationships by focusing on and delivering quality field-level execution.

We transitioned with our customers as they moved into oil and liquid-rich basins and responded to their needs for quality completion services in these emerging, service-intensive areas. Through capital investments, acquisitions and operational discipline, we continued to enhance our returns by focusing on the service lines we believe are most critical to our customers and are the most direct beneficiaries of the trend toward horizontal completions with longer laterals, which require more completion stages. These service lines are pressure pumping, coiled tubing, fluid handling and well servicing. For example, we deployed 43,000 hydraulic horse power (HHP) of new pressure pumping equipment in the Eagle Ford and Bakken shales and executed long-term take-or-pay contracts for an additional 210,000 HHP of pressure pumping capacity that we expect to deploy in 2011.

We believe 2010 was the year Complete broke away from the pack. The combination of current market trends, customer needs and our capabilities has Complete better positioned for excellent future growth.

LOOKING FORWARD

Our strategic focus has been consistent since our inception and remains unchanged. We are the resource play service provider of choice focused on delivering completion and production services in North America. We provide basin-specific expertise; reliable, purpose-built equipment; experienced, knowledgeable personnel; and safety-focused operations. We enable our customers to achieve their growth objectives, particularly in executing large-scale development programs in North America's leading resource plays. Based on our financial performance and the feedback from our customers, we are confident that we are effectively executing a strategy that will create value for our shareholders.

We are optimistic about activity levels in 2011 and expect continued positive trends related to the development of oil and liquid-rich resource plays such as the Eagle Ford, Bakken, Granite Wash, Niobrara and Permian. While we foresee continuing challenges in certain dry gas basins, we anticipate an overall increase in demand for our services resulting from increased drilling activity levels and, more importantly, a continued shift to service-intensive horizontal resource plays. We are encouraged by our customers' plans, which appear robust because of stable cash flows from improved commodity prices, improved access to the capital markets and capital contributed by joint-venture partners. We believe 2011 will provide a terrific environment for organic growth.

Our plans for 2011 include:

- Deploying approximately 210,000 HHP of pressure pumping capacity, all of which is under long-term contract;
- Adding five large diameter, extended-reach coiled tubing units to our fleet as we further solidify our position as a leader in the premium coiled tubing market; and
- Increasing investment in our fluid handling and well servicing business lines.

In addition to organic growth opportunities, we plan to also judiciously use the strength of our balance sheet to pursue select acquisitions that improve our competitive position and generate additional future growth opportunities. We believe the actions we have taken to advantageously position our assets in the most attractive markets and our financial strength have provided us with the ability to increase market share in the areas where we choose to compete. Vigilant focus on execution will be necessary to ensure we maintain our strong industry reputation and relationships with our customers and other stakeholders as we continue to grow our business. We will continue to monitor our customers' business plans and competitive market dynamics, and will strive to maintain the financial and operational flexibility that has contributed to our success to date.

As always, we are honored to serve you, our shareholders, and we thank you for your continued confidence and support.

Joseph C. Winkler
Chairman and Chief Executive Officer

FOCUS

BALANCE

DISCIPLINE

EXECUTION

Complete
Production Services

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

Form 10-K

(MARK ONE)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File No. 1-32858

Complete Production Services, Inc.
(Exact name of registrant as specified in its charter)

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**72-1503959** *(I.R.S. Employer Identification No.)*
11700 Katy Freeway, Suite 300 **Houston, Texas** *(Address of principal executive offices)*	**77079** *(Zip Code)*

Registrant's telephone number, including area code: (281) 372-2300

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

Title of each class	Name of each exchange on which registered
Common stock, $0.01 par value	**New York Stock Exchange**

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

Indicate by check mark whether 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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

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

As of June 30, 2010, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $935,388,997 based upon the closing price on the New York Stock Exchange on that date.

Number of shares of the Common Stock of the registrant outstanding as of February 14, 2011: 78,592,455

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement to be furnished to the stockholders in connection with its 2011 Annual Meeting of Stockholders are incorporated by reference in Part III, Items 10-14 of this Annual Report on Form 10-K for the fiscal year ending December 31, 2010 (this "Annual Report").

Complete Production Services, Inc.

TABLE OF CONTENTS

PART I

Unless otherwise indicated, all references to "we," "us," "our," "our company," or "Complete" include Complete Production Services, Inc. and its consolidated subsidiaries.

Item 1. *Business*

Our Company

Complete Production Services, Inc., formerly named Integrated Production Services, Inc., is a Delaware corporation formed on May 22, 2001. We focus on providing specialized completion and production services and products that help oil and gas companies develop hydrocarbon reserves, reduce costs and enhance production. We operate in basins within North America that we believe have attractive long-term potential for growth, and we deliver targeted, value-added services and products required by our customers within each specific basin. We believe our range of services and products positions us to meet many needs of our customers at the wellsite, from drilling and completion through production and eventual abandonment. We seek to differentiate ourselves from our competitors through our local leadership, our basin-level expertise and the innovative application of proprietary and other technologies. We deliver solutions to our customers that we believe lower their costs and increase their production in a safe and environmentally friendly manner. Virtually all of our operations are located in basins within North America, where we manage our operations from regional field service facilities located throughout the U.S. Rocky Mountain region, Texas, Oklahoma, Louisiana, Arkansas, Pennsylvania, western Canada and Mexico. We also have operations in Southeast Asia.

Company History

On September 12, 2005, Integrated Production Services, Inc. ("IPS"), Complete Energy Services, Inc. and I.E. Miller Services, Inc. were combined and became Complete Production Services, Inc. in a transaction in which IPS served as the acquirer.

In April 2006, we completed our initial public offering and became subject to the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act").

Our Operating Segments

Our business is comprised of three segments:

Completion and Production Services. Through our completion and production services segment, we establish, maintain and enhance the flow of oil and gas throughout the life of a well. This segment is divided into the following primary service lines:

- *Intervention Services.* Well intervention requires the use of specialized equipment to perform an array of wellbore services. Our fleet of intervention service equipment includes coiled tubing units, pressure pumping units, nitrogen units, well service rigs, snubbing units and a variety of support equipment. Our intervention services provide customers with innovative solutions to complete oil and gas wells and increase production.
- *Downhole and Wellsite Services.* Our downhole and wellsite services include electric-line, slickline, production optimization, production testing, rental and fishing services.
- *Fluid Handling.* We provide a variety of services to help our customers obtain, move, store and dispose of fluids that are involved in the development and production of their reservoirs. Through our fleet of specialized trucks, frac tanks and other assets, we provide fluid transportation, heating, pumping and disposal services for our customers.

Drilling Services. Through our drilling services segment, we provide contract drilling and specialized rig relocation and logistics services.

Product Sales. We provide oilfield service equipment and refurbishment of used equipment through our Southeast Asian business, and we provide repair work and fabrication services for our customers at a business located in Gainesville, Texas.

Our Industry

Our business depends on the level of exploration, development and production expenditures made by our customers. These expenditures are driven by the current and expected future prices for oil and gas, and the perceived stability and sustainability of those prices, as well as production depletion rates and the resultant levels of cash flows generated and allocated by our customers to their drilling and workover budgets. Our business is primarily driven by oil, natural gas and associated natural gas liquids-directed drilling activity in North America.

As illustrated in the table below, natural gas and oil commodity prices had risen in recent years but then began to decline in late 2008. While the price of oil rebounded somewhat in 2009 and continued to rise throughout 2010, the price of natural gas remained relatively low in 2010. The WTI Cushing spot price of a barrel of crude oil reached an all-time high of $145.31 per barrel in July 2008 and then dropped sharply by the end of the year, falling as low as $30.28 per barrel on December 23, 2008 before trending upwards again in late 2009 and reaching a high of $91.48 towards the end of 2010. The number of drilling rigs under contract in the United States and Canada and the number of active well service rigs decreased in 2009 but rebounded in 2010, according to Baker Hughes Incorporated ("BHI") and the Cameron International Corporation/Guiberson/AESC Service Rig Count for "Active Rigs." The table below sets forth average daily closing prices for the WTI Cushing spot oil price and the average daily closing prices for the Henry Hub price for natural gas since 2001:

Period	Average Daily Closing Henry Hub Spot Natural Gas Prices ($/mcf)	Average Daily Closing WTI Cushing Spot Oil Price ($/bbl)
1/1/01 — 12/31/01	$3.99	$25.96
1/1/02 — 12/31/02	3.37	26.17
1/1/03 — 12/31/03	5.49	31.06
1/1/04 — 12/31/04	5.90	41.51
1/1/05 — 12/31/05	8.89	56.56
1/1/06 — 12/31/06	6.73	66.09
1/1/07 — 12/31/07	6.97	72.23
1/1/08 — 12/31/08	8.89	99.92
1/1/09 — 12/31/09	3.94	61.99
1/1/10 — 12/31/10	4.38	79.48

Source: Bloomberg NYMEX prices.

The closing spot price of a barrel of WTI Cushing oil at December 31, 2010 was $91.38, and the closing spot price for Henry Hub natural gas ($/mcf) was $4.41. At February 14, 2011, the closing spot price of a barrel of WTI Cushing oil was $84.81 and the closing spot price for Henry Hub natural gas was $3.92.

Trends which we believe are affecting, and will continue to affect, our industry include:

Trend toward drilling and developing unconventional North American hydrocarbon resources. Due to the maturity of conventional North American oil and gas reservoirs and the relative abundance of undeveloped unconventional resources, an increasing proportion of future North American oil and gas will come from unconventional resources, which include tight sands, shales and coalbed methane. Development of unconventional resources typically require more wells to be drilled and maintained on tighter acreage spacing and often employ horizontal drilling and completion techniques, which are more service intensive. The appropriate technology to recover unconventional gas resources varies from region to region; therefore, knowledge of local conditions and operating procedures, and selection of the right technologies, is key to providing customers with appropriate solutions.

The advent of the resource play. A "resource play" is a term used to describe an accumulation of hydrocarbons known to exist over a large area which, when compared to a conventional play, has lower commercial development risks and a higher average decline rate. Once identified, resource plays have the potential to make a material impact because of their size and long reserve life. The application of appropriate technology and program execution are important to obtain value from resource plays. Resource play developments occur over long periods of time, well by well, in large-scale developments that repeat common tasks in an assembly-line fashion and capture economies of scale to drive down costs.

Complex technologies, techniques and equipment. The development of unconventional oil and gas resources is driving the need for complex, new technologies, completion techniques and equipment to help increase recovery rates, lower production costs and accelerate field development.

Increased Service Intensity. Advances in horizontal drilling and completion technologies and techniques have made the development of many unconventional resources such as oil and natural gas shale formations economically attractive. The North American horizontal rig count has risen from 335 at the beginning of 2007 to 947 at the end of December 2010, according to Baker Hughes, Inc. Additionally, the length of well laterals has increased and the intervals between stages has decreased over the past several years. The longer laterals and increasing number of stages has enhanced recoveries and lowered field development costs while causing the number of completion stages to grow at a faster rate than the horizontal rig count, creating an increased demand for completion related services.

Enhanced Economics in Oil- and Liquids-Rich Formations. While the majority of U.S. drilling rigs are currently drilling in natural gas formations, there is increasing horizontal drilling and completion related activity in oil- and liquid-rich formations such as the Eagle Ford, Bakken and Niobrara Shales and various other plays in Texas and Oklahoma, including the Granite Wash. We believe that the oil and natural gas liquids content in these plays significantly enhance the returns for our customers relative to opportunities in dry gas basins due to the significant disparity between oil and natural gas prices on a Btu basis. We believe the price disparity will continue over the near to mid-term resulting in increasing demand for services in oil- and liquid-rich basins.

Our Business Strategy

Our goal is to build the leading oilfield services company focused on the completion and production phases in the life of an oil and gas well. We intend to capitalize on the emerging trends in the North American marketplace through the execution of a growth strategy that consists of the following components:

Focus on execution and performance. We have established and intend to develop further a culture of performance and accountability. Senior management spends a significant portion of its time ensuring that our customers receive the highest levels of service quality and execution at the well site by focusing on the following:

- clear business direction;
- thorough planning process;
- clearly defined targets and accountabilities;
- close performance monitoring;
- safety objectives;
- performance incentives for management and employees; and
- effective communication.

Expand and capitalize on local leadership and basin-level expertise. A key component of our strategy is to build upon our base of strong local leadership and basin-level expertise. We have a significant presence in most of the key onshore continental U.S. and Canadian resource plays that we believe have the potential for long-term growth. Our position in these basins capitalizes on our local leadership as these employees have accumulated a valuable knowledge base and strong customer relationships. We intend to leverage our existing market presence, expertise and customer relationships to expand our business within these resource plays. We also intend to replicate this approach in new regions by building and acquiring new businesses that have strong regional management with extensive local knowledge.

Develop and deploy technical and operational solutions. We are focused on developing and deploying technical services, equipment and expertise that lower our customers' costs.

Capitalize on organic and acquisition-related growth opportunities. We believe there are numerous opportunities to expand our service offerings in our current geographic areas and to sell our current services and products to customers in new geographic areas. We have a proven track record of organic growth and successful acquisitions, and we intend to continue using capital investments and acquisitions to strategically expand our business over the long-term. In 2009, we significantly reduced our capital expenditures and did not complete any cash acquisitions primarily due to difficult market conditions. In 2010, we increased our capital investment significantly compared to the prior year and we acquired three small strategic businesses. We continue to evaluate additional business acquisition opportunities.

Our Competitive Strengths

We believe that we are well positioned to execute our strategy and capitalize on opportunities in the North American oil and gas market based on the following competitive strengths:

Strong local leadership and basin-level expertise. We operate our business with a focus on each regional basin complemented by our local reputations. We believe our local and regional businesses, some of which have been operating for more than 50 years, provide us with a significant advantage over many of our competitors. Our managers, sales engineers and field operators have extensive expertise in their local geological basins and understand the regional challenges our customers face. We support our local operations personnel through corporate teams that provide service specific technical support and executive level contacts. We have long-term relationships with many customers, and most of the services and products we offer are sold or contracted at a local level, allowing our operations personnel to leverage all of our expertise to establish ourselves as the preferred provider of our services in the basins in which we operate.

Significant presence in major North American basins. We operate in major oil and gas producing regions of the U.S. Rocky Mountains, Texas, Louisiana, Arkansas, Pennsylvania, Oklahoma, western Canada and Mexico, with concentrations in key "resource play" and unconventional basins. Resource plays are expected to continue to increase in importance in future North American oil and gas production as more conventional resources enter later stages of the exploration and development cycle. We believe we have an excellent position in highly active markets such as the Bakken Shale area of North Dakota, the Niobrara Shale of northeast Colorado and southeast Wyoming, the Granite Wash of northern Texas and western Oklahoma, the Marcellus Shale of Pennsylvania, the Barnett Shale of north Texas, the Haynesville Shale area of east Texas and northern Louisiana and the Eagle Ford shale in south Texas. Each of these markets is among the most active areas for exploration and development of onshore oil and gas. Accelerating production and driving down development and production costs are key goals for oil and gas operators in these areas, resulting in higher demand for our services and products. In addition, our presence in these regions allows us to build solid customer relationships and take advantage of cross-selling opportunities.

Focus on complementary production and field development services. Our breadth of service and product offerings positions us well relative to our competitors. Our services encompass the entire lifecycle of a well from drilling and completion, through production and eventual abandonment. We deliver complementary services and products, which we may provide in tandem or sequentially over the life of the well. This suite of services and products gives us the opportunity to cross-sell to our customer base throughout our geographic regions. Leveraging our local leadership and basin-level expertise, we are able to offer expanded services and products to existing customers or current services and products to new customers.

Innovative approach to technical and operational solutions. We develop and deploy services and products that enable our customers to increase production rates, stem production declines and reduce the costs of drilling, completion and production. The significant expertise we have developed in our areas of operation offers our customers customized operational solutions to meet their particular needs. Our ability to develop these technical and operational solutions is possible due to our understanding of applicable technology, our basin-level expertise and our close local relationships with customers.

Modern and active asset base. We have a modern and well-maintained fleet of coiled tubing units, pressure pumping equipment, wireline units, well service rigs, snubbing units, fluid transports, frac tanks and other specialized equipment. We believe our ongoing investment in our equipment allows us to better serve the diverse and increasingly challenging needs of our customer base. New equipment is generally less costly to maintain and operate on an annual basis and is more efficient for our customers. Modern equipment reduces downtime, including associated costs and expenditures, and enables increased utilization of our assets. We believe our future expenditures will be used to capitalize on growth opportunities within the areas we currently operate and to build out platforms in new regions.

Experienced management team with proven track record. Each member of our operating management team has extensive experience in the oilfield services industry. We believe that their considerable knowledge of and experience in our industry enhances our ability to operate effectively throughout industry cycles. Our management also has substantial experience in identifying, completing and integrating acquisitions. In addition, our management supports local leadership by developing corporate strategy, overseeing corporate governance procedures and administering a company-wide safety program.

Overview of Our Segments

We manage our business through three segments: completion and production services, drilling services and product sales. Within each of these segments, we perform services and deliver products, as detailed in the table below. We constantly monitor the North American market for opportunities to expand our business by building our presence in existing regions and expanding our services and products into attractive, new regions.

See Note 15 of the notes to the consolidated financial statements included elsewhere in this Annual Report for financial information about our operating segments and about geographic areas.

Product/Service Offering	North Texas	South Texas	North Louisiana/ East Texas	Central & Western Oklahoma	Eastern Oklahoma & Arkansas	DJ Basin (CO)	Western Slope (CO & UT)	Wyoming	North Rockies (MT & ND)	Appalachia (PA)	Western Canadian Sedimentary Basin	Mexico
Completion and Production Services:												
Coiled Tubing	✓	✓	✓	✓	✓			✓	✓	✓		✓
Pressure Pumping	✓	✓							✓	✓		
Well Servicing	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		
Fluid Handling	✓	✓	✓	✓	✓	✓	✓	✓	✓			
Snubbing		✓						✓		✓		
Electric-line	✓			✓		✓		✓	✓	✓	✓	
Slickline		✓	✓					✓			✓	
Production Optimization	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	
Production Testing		✓	✓			✓	✓	✓				✓
Rental Equipment	✓		✓	✓	✓	✓	✓	✓	✓	✓		
Pressure Testing							✓	✓	✓			
Drilling Services:												
Contract Drilling	✓											
Drilling Logistics	✓	✓	✓	✓	✓		✓		✓			
Product Sales:												
Fabrication and repair	✓											

"✓" denotes a service or product currently offered by us in this area.

Completion and Production Services (87% of Revenue for the Year Ended December 31, 2010)

Through our completion and production services segment, we establish, maintain and enhance the flow of oil and gas throughout the life of a well. This segment is divided into intervention services, downhole and wellsite services and fluid handling.

Intervention Services

We use our intervention assets, which include coiled tubing units, pressure pumping equipment, nitrogen units, well service rigs and snubbing units to perform three major types of services for our customers:

- *Completion Services.* As newly drilled oil and gas wells are prepared for production, our operations may include selectively perforating the well casing to access producing zones, stimulating and testing these zones and installing downhole equipment. We provide intervention services and products to assist in the performance of these services. The completion process typically lasts from a few days to several weeks, depending on the nature and type of the completion. Oil and gas producers use our intervention services to complete their wells because we have well-maintained equipment, well-trained employees, the experience necessary to perform such services and a strong record for safety and reliability.

- *Workover Services.* Producing oil and gas wells occasionally require major repairs or modifications, called "workovers." These services include extensions of existing wells to drain new formations either through deepening wellbores to new zones or by drilling horizontal lateral wellbores to improve reservoir drainage patterns. In less extensive workovers, we provide services and products to seal off depleted zones in existing wellbores and access previously bypassed productive zones. Other workover services which we provide include: major subsurface repairs, such as casing repair or replacement; recovery of tubing and removal of foreign objects in the wellbore; repairing downhole equipment failures; plugging back the bottom of a well to reduce the amount of water being produced; cleaning out and recompleting a well if production has declined; and repairing leaks in the tubing and casing.

- *Maintenance Services.* Maintenance services are required throughout the life of most producing oil and gas wells to ensure efficient and continuous operation. We provide services that include mechanical repairs necessary to maintain production from the well, such as repairing inoperable pumping equipment or replacing defective tubing, and removing debris from the well. Other services include pulling rods, tubing, pumps and other downhole equipment out of the wellbore to identify and repair a production problem.

The key intervention assets we use to perform intervention services are as follows:

Coiled Tubing Units and Nitrogen Units

We are one of the leading providers of coiled tubing services in North America. We operate a fleet of coiled tubing units, as well as nitrogen units. We use these assets to perform a variety of wellbore applications, including plug drilling, foam washing, acidizing, displacing, cementing, gravel packing, fishing and jetting. Coiled tubing is a key segment of the well service industry today, which allows operators to continue production during service operations without shutting in the well, thereby reducing the risk of formation damage. The growth in deep well and horizontal drilling has increased the market for coiled tubing. We provide coiled tubing services primarily in Oklahoma, Texas, Louisiana, Arkansas, Pennsylvania, Wyoming, North Dakota and Mexico.

Pressure Pumping Services

We operate fleets of pressure pumping equipment in the Barnett Shale of north Texas, in the Bakken Shale of North Dakota, in the Marcellus Shale of Pennsylvania and in the Eagle Ford shale of south Texas through which we provide stimulation and cementing services principally to oil and gas production companies.

Stimulation services primarily consist of hydraulic fracturing of hydrocarbon bearing formations which lack permeability to permit the natural flow. The fracturing process consists of pumping fluids into a well at pressures that are sufficient enough to fracture the formation. Materials such as sand and synthetic proppants are pumped into the fracture to prop open the fracture, permitting the hydrocarbons in the formation to flow into the wellbore and ultimately to the surface. Various pieces of specialized equipment are used in the process, including a blender, which is used to blend the proppant into the fluid, multiple high pressure pumping units capable of pumping significant volumes at high pressures, and real-time monitoring equipment where the progress of the process is controlled. Our fracturing units are capable of pumping slurries at pressures up to 10,000 pounds per square inch.

Cementing services consist of blending special cement with water and various solid and liquid additives to form a cement slurry that can be pumped into a well between the casing and the wellbore. Cementing services are principally performed in connection with primary cementing, where the casing used to line a wellbore after a well has been drilled is cemented into place. The purpose of primary cementing is to isolate fluids behind the casing between productive formations and non-productive formations that could damage the productivity of the well or damage the quality of freshwater acquifers, seal the casing from corrosive formation fluids and to provide structural support for the casing string.

Well Service Rigs

We own and operate a large fleet of well service rigs, of which a significant number were either recently constructed or have been recently rebuilt. We believe we have leading market positions in the Barnett Shale region of north Texas, the Haynesville Shale of east Texas and northern Louisiana and in some of the most active basins of the U.S. Rocky Mountain region. We also operate swabbing units, some of which are highly customized hydraulic units which we use to diagnose and remediate gas well production problems. We provide well service rig operations in Wyoming, Colorado, Utah, Montana, North Dakota, Pennsylvania, Louisiana, Oklahoma and Texas. These rigs are used to perform a variety of completion, workover and maintenance services, such as installations, completions, assisting with perforating, removing defective equipment and sidetracking wells.

Snubbing Units

We operate a fleet of snubbing units, several of which are rig assist units. Snubbing services use specialized hydraulic well service units that permit an operator to repair damaged casing, production tubing and downhole production equipment in high-pressure, "live-well" environments. A snubbing unit makes it possible to remove and replace downhole equipment while maintaining pressure in the well. Applications for snubbing units include "live-well" completions and workovers, underground blowout control, underbalanced completions, underbalanced drilling and the snubbing of tubing, casing or drillpipe into or out of the wellbore. Our snubbing units operate primarily in Texas, Wyoming and Pennsylvania.

Downhole and Wellsite Services

We provide an array of complementary downhole and wellsite services that we classify into four groups: wireline services; production optimization services; production testing services; and rental, fishing and pressure testing services.

Wireline Services. We own and operate a fleet of wireline units in North America and provide both electric-line and slickline services. Wireline services are used to evaluate downhole well conditions, to initiate production from a formation by perforating a well's casing, and to provide mechanical services such as setting equipment in the well, or fishing lost equipment out of a well. We provide wireline services in the western Canadian Sedimentary Basin, Wyoming, Colorado, North Dakota, Pennsylvania, Oklahoma and Texas.

With our fleet of wireline equipment we provide the following services:

Electric-Line Services:

- *Perforating Services.* Perforating involves positioning a perforating gun that contains explosive jet charges down the wellbore next to a productive zone. A detonator is fired and primer cord is ignited, which then detonates the jet charges. The resulting explosion burns a hole through the wellbore casing and cement and into the formation, thus allowing access to the formation. The perforating gun may be deployed in a number of ways. The gun can be conveyed by a conventional wireline cable if the wellbore geometry allows, it may be conveyed on coiled tubing, it may be conveyed on conventional tubing or the gun may be "pumped-down" to the correct depth in the wellbore.
- *Logging Services.* Logging requires the use of a single or multi-conductor, braided steel cable (electric-line), mounted on a hydraulically operated drum, and a specialized logging truck. Electronic instruments are attached to the end of the cable and lowered to the bottom of the well and the line is slowly pulled out of the well, transmitting wellbore data up the cable to the surface where the

information is processed by a surface computer system and displayed on a graph in a logging format. This information is used by customers to analyze different downhole formation structures, to detect the presence of oil, gas and water and to check the integrity of the casing or the cement behind the pipe. Logs are also used to detect gas or fluid migration between zones or to the surface.

- *Slickline Services.* Slickline services are used primarily for well maintenance. The line used for this application is generally a small single steel line. Typical applications of this service would include bottom hole pressure surveys, running temperature gradients, setting tubing plugs, opening and closing sliding sleeves, fishing operations, plunger lift installations, gas lift installations and other maintenance services that a well might require during its lifecycle.

Production Optimization Services. Our production optimization services provide customers with technical solutions to stem declining production that results from liquid loading, reduced bottom-hole pressures or improper wellsite designs. We assist in identifying candidates, designing solutions, executing on-site and following up to ensure continued performance. We have developed proprietary technologies that allow us to enhance recovery for our customers and provide on-going service. We offer production optimization services to customers across the United States and in Canada. Specific services we provide include:

- *Plunger Lift Services and Products.* We provide plunger lift candidate selection, installation and maintenance services which may incorporate the use of our patented Pacemaker Plunger Lift System. Plunger lift systems facilitate the removal of fluids that restrict the production of natural gas wells. Removing fluids that accumulate in wells increases production and, in many cases, slows decline rates. The proprietary design of our Pacemaker Plunger Lift System incorporates a large bypass area which allows it to make more trips per day and remove more wellbore fluids, versus other plunger lift designs, in wells with certain characteristics.

- *Gas Lift Services and Products.* We provide gas lift candidate selection, installation and maintenance services. Gas lift systems facilitate the removal of fluids that restrict the production of natural gas wells. Evacuating fluids that accumulate in wells increases production and, in many cases, slows decline rates. Gas is injected down the tubing-casing annular and enters the tubing string through a valve to aerate liquids above an entrance point to reduce hydrostatic pressure. Valves are set at varying depths and pressures throughout the tubing string to aerate the fluid column. This practice reduces bottom hole pressure, resulting in an increase in production.

- *Acoustic Pressure Surveys.* We provide acoustic pressure surveys, an analytical technique that assists our customers in determining static reservoir pressure and the existence of near wellbore formation damage.

- *Dynamometer Analysis.* Our dynamometer analysis services include the analysis of reciprocating rod pumping systems (pumpjacks) to determine pump performance and provide our customers with critical information for well performance used to optimize the production and recovery of oil and gas.

- *Fluid Level Analysis.* We provide fluid level analysis services which record an acoustic pulse as it travels down the wellbore in order to determine the fluid depth.

Production Testing Services. Production testing is a service required by exploration and production companies to evaluate and clean out new and existing wells. We provide production testing services in Wyoming, Utah, Colorado, Texas and Mexico.

Production testing has the following primary applications:

- *Well clean-ups or flowbacks* are done shortly after completing or stimulating a well and are designed to remove damaging drilling fluids, completion fluids, sand and other debris. This "clean-up" prevents damage to the permanent production facilities and flowlines, thereby improving production. Our clean-up offering includes our Green Flowback services, which permit the flow of gas to our customers while performing drill-outs and flowback operations, increasing production, accelerating time to production and eliminating the need to flare gas.

- *Exploration well testing* measures how a reservoir performs under various flow conditions. These measurements allow reservoir and production engineers and geologists to understand well or reservoir production capabilities. Exploration testing jobs can last from a few days to several months.

- *In-line production testing* measures well flow rates, oil, gas and water composition, pressure and temperature. These measurements are used by engineers to identify and solve well and reservoir problems. In-line production testing is performed after a well has been completed and is already producing. In-line tests can run from several hours to more than several months.

Rental Equipment, Fishing and Pressure Testing Services. Oil and gas producers and drilling contractors often need specialized tools, drillpipe, pressure testing equipment and other equipment and need qualified personnel to operate this equipment. In response to this need, we provide the following services and products:

- *Rental Equipment and Services.* We rent specialized tools, equipment and tubular goods for the drilling, completion and workover of oil and gas wells. Items rented include pressure control equipment, drill string equipment, pipe handling equipment, fishing and downhole tools, as well as other equipment such as stabilizers, power swivels and bottom-hole assemblies.

- *Fishing Services.* We provide highly-skilled downhole services, including fishing, milling and cutting services, which consist of removing or otherwise eliminating "fish" or "junk" (a piece of equipment, a tool, a part of the drill string or debris) in a well that is causing an obstruction. We also install whipstocks to sidetrack wells, provide plugging and abandonment services, as well as pipe and wireline recovery services, foam services and casing patch installation.

- *Pressure Testing Services.* We provide specialized pressure testing services which involve the use of truck-mounted equipment designed to carry small fluid volumes with high pressure pumps and hydraulic torque equipment. This equipment is primarily used to perform pressure tests on flow line, pressure vessels, lubricators, well heads and casings and tubing strings. The units are also used to assemble and disassemble blowout preventors ("BOPs") for the drilling and work over sector. We have developed specialized, multi-service pressure testing units that enable one or two employees to complete multiple services simultaneously. We have multi-service pressure testing units that we operate in Colorado, North Dakota, Utah, Wyoming and Mexico.

Fluid Handling

Oil and gas operations use and produce significant quantities of fluids. We provide a variety of services to assist our customers to obtain, move, store and dispose of fluids that are involved in the development and production of their reservoirs. We provide fluid handling services in Texas, Oklahoma, Louisiana, Colorado, Wyoming, Arkansas, North Dakota and Montana.

- *Fluid Transportation.* We operate specialized transport trucks to deliver, transport and dispose of fluids safely and efficiently. We transport fresh water, completion fluids, produced water, drilling mud and other fluids to and from our customers' wellsites. Our assets include U.S. Department of Transportation certified equipment for transportation of hazardous waste.

- *Frac Tank Rental.* We operate a fleet of frac tanks that are often used during hydraulic fracturing operations. We use our fleet of fluid transport assets to fill and empty these tanks and we deliver and remove these tanks from the wellsite with our fleet of winch trucks.

- *Fluid Disposal.* We own salt water disposal wells in Oklahoma, Texas, Colorado and Arkansas and one evaporation facility in Wyoming. These facilities are used to dispose of water from fracturing operations and from fluids produced during the routine production of oil and gas.

- *Other Services.* We own and operate a fleet of hot oilers and superheaters, which are assets capable of heating high volumes of fluids. We also sell fluids used during well completions, such as fresh water and potassium chloride, and drilling mud, which we move to our customers' wellsites using our fluid transportation services.

Drilling Services (11% of Revenue for the Year Ended December 31, 2010)

Through our drilling services segment, we deliver services that initiate oil and gas production by providing land drilling and specialized rig logistics.

Contract Drilling

We provide contract drilling services to major oil companies and independent oil and gas producers in and around the Barnett Shale region of north Texas and the Permian Basin in west Texas. Contract drilling services are primarily provided under a standard day rate, and, to a lesser extent, footage or turnkey contracts. Drilling rigs vary in size and capability and may include specialized equipment. The majority of our drilling rig fleet is equipped with mechanical power systems and has depth ratings ranging from approximately 8,000 to 15,000 feet.

Drilling Logistics

Through our owned and operated fleet of specialized trucks, we provide drilling rig mobilization services primarily in Louisiana, Texas, North Dakota, Colorado and Arkansas. Our capabilities allow us to move the largest rigs in the United States. Our operations are strategically located in regions where approximately 50% of the land drilling rigs in the United States are located. We believe our highly skilled personnel position us as one of the leading rig moving companies in the industry.

Product Sales (2% of Revenue for the Year Ended December 31, 2010)

Through our product sales segment, we provide a variety of equipment used by oil and gas companies throughout the lifecycle of their wells. We assemble and refurbish equipment at our fabrication shop in north Texas. In addition, we operate an oilfield sales, service and rental business based in Singapore. This business sells new and reconditioned equipment used in the construction and upgrade of offshore drilling rigs; rents mud coolers, tubular handling equipment, BOPs and other service tools; and provides machining and repair services.

Sales and Marketing

Most sales and marketing activities are performed through our local operations in each geographical region. We believe our local field sales personnel have an excellent understanding of basin-specific issues and customer operating procedures and, therefore, can effectively target marketing activities. We supplement our field sales efforts with corporate teams that provide service specific technical support and executive level contacts.

Customers

Our customers consist of large multi-national and independent oil and gas producers, as well as smaller independent producers and the major land-based drilling contractors in North America. Our top ten customers accounted for approximately 52%, 49% and 45% of our revenue for the years ended December 31, 2010, 2009 and 2008, respectively. Our top two customers provided 12.2% and 10.7% of our total annual revenue in 2010, and the same two customers provided 9.9% and 9.7% of our total annual revenue in 2009. No customer represented more than 10% of our total annual revenue in 2008. We believe we have a broad customer base and wide geographic coverage of operations, which somewhat insulates us from regional or customer specific circumstances.

Our top ten customers for the year ended December 31, 2010 were as following (in alphabetical order):

Anadarko Petroleum Corporation
Chesapeake Energy Corporation
Chief Oil & Gas, LLC
Continental Resources, Inc.
Devon Energy Corporation
EOG Resources, Inc.
Exxon Mobil Corporation
Noble Energy, Inc.
Petroleos Mexicanos (Pemex)
The Williams Companies, Inc.

Seasonality

Our completion and production services business generally experiences a decline in sales for our Canadian operations during the second quarter of each year due to seasonality, as weather conditions make oil and gas operations in this region difficult during this period. Our Canadian operations accounted for approximately 5% of total revenues from continuing operations for each of the years ended December 31, 2010, 2009 and 2008. To a lesser extent, seasonality can affect our operations in the Appalachian region and certain parts of the Rocky Mountain and Mid-continent regions, which may be subject to periods of reduced activity due to inclement weather conditions, road restrictions and environmental stipulations.

Operating Risk and Insurance

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

- personal injury or loss of life;
- damage or destruction of property, equipment and the environment; and
- suspension of operations.

In addition, claims for loss of oil and 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 have suffered accidents in the past and anticipate that we will 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 compensation 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 commercial general liability, workers' compensation, business auto, excess auto liability, commercial property, rig physical damage and contractor's equipment, motor truck cargo, umbrella liability and excess liability, non-owned aircraft liability, directors and officers, employment practices liability, fiduciary and commercial crime insurance policies. However, any insurance obtained by us may not be adequate to cover any losses or liabilities and this insurance may not 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. See Item 1A. "Risk Factors."

Competition

The markets in which we operate are highly competitive. To be successful, a company must provide services and products that meet the specific needs of oil and gas exploration and production companies and drilling services contractors at competitive prices.

We provide our services and products across North America, and we compete against different companies in each service and product line we offer. Our competition includes many large and small oilfield service companies, including the largest integrated oilfield services companies.

Our major competitors for our completion and production services segment include Schlumberger Ltd., Baker Hughes Incorporated, Halliburton Company, Weatherford International Ltd., Key Energy Services, Inc., Basic Energy Services, Inc., Nabors Industries Ltd., RPC Inc. and a significant number of locally-oriented businesses. In our drilling services segment, our primary competitors include Nabors Industries Ltd., Patterson-UTI Energy, Inc., Unit Corporation, Helmerich & Payne and Precision Drilling Corporation. Our principal competitors in our product sales segment include National Oilwell Varco, Inc. and various smaller providers of equipment. We believe that the principal competitive factors in the market areas that we serve are quality of service and products, reputation for safety and technical proficiency, availability and price. While we must be competitive in our pricing, we believe our customers select our services and products based on local leadership and basin-expertise that our personnel use to deliver quality services and products.

Government Regulation

We operate under the jurisdiction of a number of regulatory bodies that regulate worker safety standards, the handling of hazardous materials, the transportation of explosives, the protection of the environment and driving standards of operation. Regulations concerning equipment certification create an ongoing need for regular maintenance which is incorporated into our daily operating procedures. The oil and gas industry is subject to environmental regulation pursuant to local, state and federal legislation.

Among the services we provide, we operate as a motor carrier and therefore are subject to regulation by the U.S. Department of Transportation and by various state agencies. These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations and regulatory safety, financial reporting and certain mergers, consolidations and acquisitions. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may affect the economics of the industry by requiring changes in operating practices or by changing the demand for common or contract carrier services or the cost of providing truckload services. Some of these possible changes include increasingly stringent environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive in any specific period, onboard black box recorder devices or limits on vehicle weight and size.

Interstate motor carrier operations are subject to safety requirements prescribed by the U.S. Department of Transportation. To a large degree, intrastate motor carrier operations are subject to safety regulations that mirror federal regulations. Such matters as weight and dimension of equipment are also subject to federal and state regulations. Department of Transportation regulations mandate drug testing of drivers.

From time to time, various legislative proposals are introduced, including proposals to increase federal, state, or local taxes, including taxes on motor fuels, which may increase our costs or adversely impact the recruitment of drivers. We cannot predict whether, or in what form, any increase in such taxes applicable to us will be enacted.

Environmental Matters

Our operations are subject to numerous federal, state, local and foreign environmental laws and regulations governing the release and/or discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies issue regulations to implement and enforce these laws, for which compliance is often costly and difficult. The violation of these laws and regulations may result in the denial or revocation of permits, issuance of corrective action orders, assessment of administrative and civil penalties, and even criminal prosecution. We believe that we are in substantial compliance with applicable environmental laws and regulations. Further, we do not anticipate that compliance with existing environmental laws and regulations will have a material effect on our consolidated financial statements. However, it is possible that substantial costs for compliance or penalties for non-compliance may be incurred in the future. Moreover, it is possible that other developments, such as the adoption of stricter environmental laws, regulations, and enforcement policies, could result in additional costs or liabilities that we cannot currently quantify.

We generate wastes, including hazardous wastes, which are subject to the federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or EPA, the Nuclear Regulatory Commission, and state agencies have limited the approved methods of disposal for some types of hazardous and nonhazardous wastes. Some wastes handled by us in our field service activities that currently are exempt from treatment as hazardous wastes may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes. If this were to occur, we would become subject to more rigorous and costly operating and disposal requirements.

The federal Comprehensive Environmental Response, Compensation, and Liability Act, CERCLA or the "Superfund" law, and comparable state statutes impose liability, without regard to fault or legality of the original conduct, on classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed of or arranged for the disposal of hazardous substances at offsite locations such as landfills. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own, lease, or operate numerous properties and facilities that for many years have been used for industrial activities, including oil and gas production operations. Hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of hazardous substances, wastes, or hydrocarbons, was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes (including substances disposed of or released by prior owners or operators), remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills), or perform remedial plugging of disposal wells or pit closure operations to prevent future contamination. These laws and regulations may also expose us to liability for our acts that were in compliance with applicable laws at the time the acts were performed.

In the course of our operations, some of our equipment may be exposed to naturally occurring radiation associated with oil and 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 gas production operations for many years, it is possible that we may incur costs or liabilities associated with elevated levels of NORM.

The Federal Water Pollution Control Act, also known as the Clean Water Act, and applicable state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters or waters of the United States. The discharge of pollutants into jurisdictional waters is prohibited unless the discharge is permitted by the EPA or applicable state agencies. Many of our properties and operations require permits for discharges of wastewater and/or stormwater, and we have a system for securing and maintaining these permits. In addition, the Oil Pollution Act of 1990 imposes a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages, including natural resource damages, resulting from such spills in waters of the United States. A responsible party includes the owner or operator of a facility. The Federal Water Pollution Control Act and analogous state laws provide for administrative, civil and criminal penalties for unauthorized discharges and, together with the Oil Pollution Act, impose rigorous requirements for spill prevention and response planning, as well as substantial potential liability for the costs of removal, remediation, and damages in connection with any unauthorized discharges.

Our underground injection operations are subject to the federal Safe Drinking Water Act, as well as analogous state and local laws and regulations. Under Part C of the Safe Drinking Water Act, the EPA established the Underground Injection Control program, which established the minimum program requirements for state and local programs regulating underground injection activities. The Underground Injection Control program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require us to obtain a permit from the applicable regulatory agencies to operate our underground injection wells. We believe that we have obtained the necessary permits from these agencies for our underground injection wells and that we are in substantial compliance with permit conditions and state 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.

Some of our operations also result in emissions of regulated air pollutants. The federal Clean Air Act and analogous state laws require permits for facilities that have the potential to emit substances into the atmosphere that could adversely affect environmental quality. Failure to obtain a permit or to comply with permit requirements could result in the imposition of substantial administrative, civil and even criminal penalties.

The U.S. Congress is considering legislation to reduce emissions of greenhouse gases. President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, have already begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, our customers could be required to purchase and surrender allowances for greenhouse gas emissions resulting from their operations. This requirement could increase our customers' operational and compliance costs and result in reduced demand for their products, which would have a material adverse effect on the demand for our services and our business.

Also, as a result of the United States Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in *Massachusetts* that greenhouse gases, including carbon dioxide, fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources. In July 2008, the EPA released an "Advance Notice of Proposed Rulemaking" regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court's decision in Massachusetts. In the notice, the EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any new federal, regional or state restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions on our customers. Such legislation could potentially make our customers products more expensive and thus reduce demand for them, which could have a material adverse effect on the demand for our services and our business.

Many foreign nations, including Canada, have agreed to limit emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol." In December 2002, Canada ratified the Kyoto Protocol. The Kyoto Protocol requires Canada to reduce its emissions of greenhouse gases to 6% below 1990 levels by 2012. The implementation of the Kyoto Protocol in Canada is expected to affect the operation of all industries in Canada, including the well service industry and its customers in the oil and natural gas industry. On April 26, 2007, the Government of Canada released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the Action Plan) also known as ecoACTION, which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and strengthens energy standards for a number of products. On March 10, 2008, the Government of Canada released details of the Action Plan's regulatory framework, which includes a requirement that all covered industrial sectors, including upstream oil and gas facilities meeting certain threshold requirements, reduce their emissions from 2006 levels by 18% by 2010. The Government of Canada is in the process of developing regulations to implement the Action Plan. As precise details of the implementation of the Action Plan have not yet been finalized, the exact effect on our operations in Canada cannot be determined at this time. It is possible that already stringent air emissions regulations applicable to our operations and the operations of our customers in Canada will be replaced with even stricter requirements prior to 2012. These requirements could increase the cost of doing business for us and our customers, reduce the demand for the oil and gas our customers produce, and thus have an adverse effect on the demand for our products and services.

We are also subject to the requirements of the federal Occupational Safety and Health Act ("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. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

Employees

As of December 31, 2010, we had 6,572 employees. Of our total employees, 5,890 were in the United States, 301 were in Canada, 298 were in Mexico and 83 were in Singapore and other locations in Southeast Asia. We are a party to certain collective bargaining agreements in Mexico. Other than these agreements in Mexico, we are not a party to any collective bargaining agreements, and we consider our relations with our employees to be satisfactory.

Website Access to Our Periodic SEC Reports

We periodically file or furnish documents to the Securities and Exchange Commission ("SEC"), including our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports as required. These reports are linked to and available from our corporate website free of charge, as soon as reasonably practicable after we file such material, or furnish it to the SEC. Our primary internet address is: **http://www.completeproduction.com.** Our website also includes certain corporate governance documentation such as our business ethics policy. As permitted by the SEC rules, we may occasionally provide important disclosures to investors by posting them in the investor relations section of our website. However, the information contained on our website is not incorporated by reference into this Annual Report and should not be considered part of this report.

The information we file with the SEC may also be read and copied at the SEC's Public Reference Room at 100F Street, N.E., Washington, D.C. 20549. In addition, the SEC maintains a website at: **http://www.sec.gov** which contains reports, proxy and other documents regarding our company which are filed electronically with the SEC.

Forward-looking Statements

Certain statements and information in this Annual Report on Form 10-K may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Act of 1995. These forward-looking statements are based on our current expectations, assumptions, estimates and projections about us and the oil and gas industry. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. These forward-looking statements involve risks and uncertainties that may be outside of our control and could cause actual results to differ materially from those in the forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to: market prices for oil and gas, the level of oil and gas drilling, economic and competitive conditions, capital expenditures, regulatory changes and other uncertainties. Other factors that could cause our actual results to differ from our projected results are described in: Item 1A. "Risk Factors." See Item 1A. "Risk Factors" and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Overview" for a discussion of trends and factors affecting us and our industry. Also see Item 8. "Financial Statements and Supplementary Data, Note 15 — Segment Reporting" for financial information about each of our business segments.

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 document 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:

- general economic and market conditions;
- our access to current or future financing arrangements;
- a decline in or substantial volatility of oil and 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;
- our ability to replace or add workers at economic rates;
- environmental and other governmental regulations including climate change related legislation; and
- the effects of severe weather on our services, centers or equipment.

In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Annual Report may not occur, and therefore, our forward-looking statements speak only as of the date of this Annual Report. Unless otherwise required by law, we undertake no obligation and do not intend to update publicly any forward-looking statements, even if new information becomes available or other events occur in the future. These cautionary statements qualify all such forward-looking statements attributable to us or persons acting on our behalf.

Item 1A. *Risk Factors.*

An investment in our common stock involves a degree of risk. You should carefully consider the following risk factors, together with the other information contained in this Annual Report and other public filings with the SEC, before deciding to invest in our common stock. Additional risks and uncertainties not currently known to us or that we currently view as immaterial may also impair our business. If any of these risks develop into actual events, our business, financial condition, results of operations or cash flows could be materially adversely affected, and you could lose all or part of your investment.

Risks Related to Our Business and Our Industry

Our business depends on the oil and gas industry and particularly on the level of activity for North American oil and gas. Our markets may be adversely affected by industry conditions that are beyond our control.

We depend on our customers' willingness to make operating and capital expenditures to explore for, develop and produce oil and gas in North America. If these expenditures decline, our business may suffer. Our customers' willingness to explore, develop and produce depends largely upon prevailing industry conditions that are influenced by numerous factors over which management has no control, such as:

- the supply of and demand for oil and gas, including current natural gas storage capacity and usage;
- the level of prices, and expectations about future prices, of oil and gas;
- the cost of exploring for, developing, producing and delivering oil and gas;
- the expected rates of declining current production;
- the discovery rates of new oil and gas reserves;
- available pipeline and other transportation capacity;
- weather conditions, including hurricanes that can affect oil and gas operations over a wide area;
- domestic and worldwide economic conditions;
- political instability in oil and gas producing countries;
- technical advances affecting energy consumption;
- the price and availability of alternative fuels;
- the access to and cost of capital for oil and gas producers; and
- merger and divestiture activity among oil and gas producers.

The level of activity in the North American oil and gas exploration and production industry is volatile. Expected trends in oil and gas production activities may not continue and demand for the services provided by us may not reflect the level of activity in the industry. Oil and natural gas prices and rotary rig counts declined sharply in the fourth quarter of 2008 and remained relatively low throughout 2009 compared to the levels in mid-2008. Although activity began to recover at the end of 2009 and improved throughout 2010, an unexpected material decline in oil and gas prices or North American activity levels could occur again and have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, a decrease in the development rate of oil and gas reserves in our market areas may also have an adverse impact on our business, even in an environment of stronger oil and gas prices.

Because the oil and gas industry is cyclical, our operating results may fluctuate.

Oil and gas prices are volatile. WTI oil commodity prices reached historic highs in 2008 then declined substantially by year end and remained at depressed levels through much of 2009. Oil prices rebounded in 2010, reaching a high of $91.48 towards the end of the year. Henry Hub natural gas prices averaged $8.89 per mcf in 2008, but exceeded $12.00 per mcf in June of 2008, before falling below $6.00 per mcf at the end of 2008. Natural gas prices did not exceed $6.11 per mcf in 2009 and averaged $3.94 per mcf during that year. Prices for natural gas rebounded somewhat in 2010, although the average was only $4.38 per mcf. Declines in oil and gas prices result in a decrease in the expenditure levels of oil and gas companies and drilling contractors which in turn adversely affects us. We have experienced in the past, and may experience in the future, significant fluctuations in operating results as a result of the reactions of our customers to actual and anticipated changes in oil and gas prices. We reported income from continuing operations in 2010 of $84.2 million, a loss from continuing operations of $181.7 million in 2009 which included a goodwill impairment loss of $97.6 million and fixed asset and other intangible impairment losses totaling $38.6 million, and a loss from continuing operations of $84.7 million in 2008 which included a goodwill impairment loss of $272.0 million.

With the exception of our pressure pumping operations, substantially all of the service and rental revenue we earn is based upon a charge for a relatively short period of time (an hour, a day, a week) for the actual period of time the service or rental is provided to our customer. By contracting services on a short-term basis, we are exposed to the risks of a rapid reduction in market price and utilization and volatility in our revenues. Product sales are recorded when the actual sale occurs, title or ownership passes to the customer and the product is shipped or delivered to the customer.

Our business depends upon our ability to obtain key materials and specialized equipment from suppliers. Shortages of these materials or equipment or an increase in the cost of these items which are used in our operations or an increase in the cost to manufacture this equipment could adversely affect our operations in the future.

We do not have long-term contracts with the third party suppliers of many of the products that we use in large volumes in our operations, including many parts we use in the manufacture of our fracturing units and pumps, coiled tubing pipe, some of the chemicals and sand we use in fracturing fluids and the fuel we use in our equipment and vehicles. During periods in which certain of our services are in high demand, the availability of the key products used in our industry decreases and the price of such products increases. Our industry has faced sporadic proppant shortages associated with pressure pumping operations requiring work stoppages which adversely impacted the operating results of several competitors and, in the fourth quarter of 2010, we experienced logistical constraints in North Dakota adversely impacting our results. In addition, rising diesel fuel prices have had a significant impact on our expenses, and adversely impacted our earnings in some periods. We are dependent on a small number of suppliers for certain parts that are in high demand in our industry. Our reliance on a small number of suppliers could increase the difficulty of obtaining such parts in the event of a shortage of those parts in our industry. Should our current suppliers be unable to provide the necessary raw materials (proppant, chemicals, cement or explosives) or finished products (such as workover rigs or fluid-handling equipment) or otherwise fail to deliver the products timely and in the quantities required, any resulting delays in the provision of services could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We rely on certain related parties (e.g., companies majority-owned by certain of our directors or current or former officers or employees) for the purchase and manufacture of a significant amount of the equipment, including pressure pumping units, used in our operations. Concentrating our equipment supply needs on one or more related parties could adversely impact our results of operations if any of the related parties experience shortages or other interruptions to their businesses. See Note 19, "Related party transactions" in our notes to consolidated financial statements included elsewhere in this Annual Report.

There is potential for excess capacity in our industry.

Because oil and gas prices and drilling activity are at high levels and service companies are seeing increasing demand for services and attractive returns on investments, oilfield service companies are ordering new equipment to expand their services. A growing supply of equipment may result in an increasingly competitive environment for oilfield service companies, which may lead to lower prices and utilization for our services which would adversely affect our business.

We are subject to federal, state and local laws and regulations regarding issues of health, safety and protection of the environment, including climate change. Under these laws and regulations, we may become liable for penalties, damages or costs of remediation or other corrective measures. Any changes in laws or government regulations could increase our costs of doing business.

Our operations are subject to stringent federal, state and local laws and regulations relating to, among other things, protection of natural resources, wetlands, endangered species, the environment, health and safety, waste management, waste disposal, and transportation of waste and other materials. Such laws and regulations include the Resource Recovery and Conservation Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Clean Water Act, the Safe Drinking Water Act and analogous state laws. Our operations pose risks of environmental liability, including leakage from our operations to surface or subsurface soils, surface water or groundwater. Some environmental laws and regulations may impose strict, joint and several liability. Therefore in some situations we could be exposed to liability as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, third parties. Actions arising under these laws and regulations could result in the shutdown of our operations, fines and penalties, expenditures for remediation or other corrective measures, and claims for liability for property damage, exposure to hazardous materials or hazardous waste, or personal injuries. Sanctions for noncompliance with applicable environmental laws and regulations also may include the assessment of administrative, civil or criminal penalties, revocation of permits, temporary or permanent cessation of operations in a particular location and issuance of corrective action orders. Such claims or sanctions and related costs could cause us to incur substantial costs or losses and could have a material adverse effect on our business, financial condition and results of operations. An increase in regulatory requirements on oil and gas exploration and completion activities could significantly delay or interrupt our operations.

If we do not perform in accordance with government, industry or our own safety standards, we could lose business from certain customers, many of whom have an increased focus on safety issues as a result of recent incidents, such as the Macondo Well event in the Gulf of Mexico, and governmental initiatives on safety and environmental issues related to E&P activities.

On June 9, 2009, companion bills entitled the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act of 2009 were introduced in the United States Senate (S. 1215) and House of Representatives (H.R. 2766). Currently, unless the fracturing fluid used in the hydraulic fracturing process contains diesel, hydraulic fracturing operations are exempt from regulation under the federal Safe Drinking Water Act. The FRAC Act would remove the permit exemption and require the United States Environmental Protection Agency (the "EPA"), to promulgate regulations on hydraulic fracturing. Further, states with delegated authority to implement the Safe Drinking Water Act would have to modify their programs to remain consistent with any new federal regulations. The FRAC Act would also require persons conducting hydraulic fracturing, such as us, to disclose the chemical constituents of their fracturing fluids to a regulatory agency. This Act would make the information public via the internet, which could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. If this or similar legislation becomes law, the legislation could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance and doing business. Currently, neither S. 1215 nor H.R. 2766 is scheduled for consideration by the Senate or the House, and it is not clear whether the 111th Congress will act on either bill. Compliance or the consequences of any failure to comply by us could have a material adverse effect on our business, financial condition and operational results.

Another bill has been introduced in Congress in 2010 that would require disclosure of chemicals used in hydraulic fracturing operations. The Clean Energy Jobs and Oil Company Accountability Act of 2010 (S. 3663) remains on the Senate Legislative Calendar under General Orders, and would amend the Emergency Planning and Community Right-to-Know Act by requiring any person using hydraulic fracturing for an oil or natural gas well to submit to the state, or make publicly available, the list of chemicals used in each hydraulic fracturing process (identified by well location and number), including the chemical constituents of mixtures, Chemical Abstracts Service registry numbers, and material safety data sheets. S. 3663 would not, however, require public disclosure of "proprietary chemical formulas."

Several states have considered, or are considering, legislation or regulations similar to the federal legislation described above or are taking action to restrict hydraulic fracturing in certain jurisdictions. In June 2010, the Wyoming Oil and Gas Conservation Commission passed a rule requiring disclosure of hydraulic fracturing fluid content. In October 2010, the Governor of Pennsylvania issued a moratorium on new natural gas development on state forest lands. In November 2010, the Pennsylvania Environmental Quality Board proposed regulations that would require reporting of the chemicals used in fracturing fluids. At this time, it is not possible to estimate the potential impact on our business of these state actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing.

On February 18, 2010, the Energy and Commerce Committee of the United States House of Representatives requested that we and other companies provide information concerning the chemicals used in hydraulic fracturing. Subsequently, we received follow-up requests from the Committee for additional information and documentation.

We have worked with the Committee's staff to provide information concerning such chemicals while at the same time acting to protect our proprietary interests and to fulfill our contractually imposed confidentiality obligations to certain customers.

Also, the EPA is reviewing the scope of its existing regulatory authority and evaluating whether and how it can regulate hydraulic fracturing. The EPA recently requested additional information from us and several other service companies concerning hydraulic fracturing. In addition, in March 2010, the EPA announced its intention to conduct a comprehensive research study, ordered by Congress, on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. As part of this study, the EPA is conducting public hearings across the country. Even if the FRAC Act or similar legislation is not adopted, the EPA study, depending on its results, could spur further initiatives to regulate hydraulic fracturing under the Safe Drinking Water Act or otherwise. The EPA has announced that the energy extraction sector is one of the sectors designated for increased enforcement over the next three to five years.

Additionally, the EPA's Tier IV regulations apply to certain off-road diesel engines that are used by us to power equipment in the field. Under these regulations, we are limited in the number of non-compliant off-road diesel engines we can purchase. Until Tier IV-compliant engines that meet our needs are available, these regulations could limit our ability to acquire a sufficient number of diesel engines to expand our fleet and to replace existing engines as they are taken out of service.

Laws protecting the environment generally have become more stringent over time and we expect them to continue to do so, which could lead to material increases in our costs for future environmental compliance and remediation. The effect of environmental laws and regulations on our business is discussed in greater detail in Item 1, "Business — Environmental Matters" of this Annual Report.

We may be exposed to certain regulatory and financial risks related to climate change.

Current and future regulatory initiatives directed at climate change may increase our operating costs and may, in the future, reduce the demand for hydrocarbons that our customers produce. In 2009 and 2010, the United States Congress considered a variety of legislation on climate change. These bills or new legislation may be considered by the current Congress. In substance, most legislative proposals contain a "cap and trade" approach to greenhouse gas regulation. Under such an approach, companies would be required to hold sufficient emission allowances to cover their greenhouse gas emissions. Over time, the total number of allowances would be reduced or expire, thereby relying on market-based incentives to allocate investment in emission reductions across the economy. As the number of available allowances declines, the cost would presumably increase. In addition to the prospect of federal legislation, several states have adopted or are in the process of adopting greenhouse gas reporting or cap-and-trade programs. Therefore, while the outcome of the federal and state legislative processes is currently uncertain, if such an approach were adopted (either by domestic legislation, international treaty obligation or domestic regulation), our operating costs could increase as could the operating costs of our customers, as they buy additional allowances or embark on emission reduction programs. Such legislation could have both a direct and indirect effect on our business.

Even without further federal legislation, the EPA has begun to regulate greenhouse gas emissions. In December 2009, the EPA released an Endangerment and Cause or Contribute Findings for Greenhouse Gases, which became effective in January 2010. This regulatory finding sets the foundation for future EPA greenhouse gas regulation under the Clean Air Act. The EPA also promulgated a new greenhouse gas reporting rule, which became effective in December 2009, and which requires facilities that emit more than 25,000 tons per year of carbon dioxide-equivalent emissions to prepare and file certain emission reports. On May 12, 2010, the EPA issued a new "tailoring" rule, which proposed and imposes additional permitting requirements on certain stationary sources emitting over 75,000 tons per year of carbon dioxide equivalent emissions. The EPA is considering additional rulemaking to apply these requirements to broader classes of emission sources by 2012, which may apply to some of our facilities. Finally, on November 8, 2010, the EPA adopted rules expanding the industries subject to greenhouse gas reporting to include certain petroleum and natural gas facilities. These rules require data collection beginning in 2011 and reporting beginning in 2012. Many of our customer's facilities are subject to these rules. As a result of these regulatory initiatives, our operating costs may increase in compliance with these programs, although we are not situated differently in this respect from our competitors in the industry. Our customer's operating costs may also increase, thereby having a potential indirect effect on our business.

Future growth in our business could strain our resources, causing us to lose customers and increase our operating expenses.

The expansion of our business through organic growth can impact us. We have experienced short-term logistical constraints in positioning assets during 2010, and expect that we might incur such constraints in the future. In addition, as we expand into new geographic regions and service lines and add new equipment, we could incur delays and will incur costs to attract, train and retain staff to crew the equipment as well as costs to adequately train these new employees. Our inability to manage our growth effectively or to maintain the quality of our services, products and personnel could have a material adverse effect on our business, financial condition or results of operations.

Changes in trucking regulations may increase our costs and negatively impact our results of operations.

We operate trucks and other heavy equipment associated with many of our service offerings. We therefore are subject to regulation as a motor carrier by the United States Department of Transportation and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. These regulatory authorities exercise broad powers over our trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing and specifications and insurance requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact our operations by requiring changes in fuel emissions limits, the hours of service regulations that govern the amount of time a driver may drive or work in any specific period, limits on vehicle weight and size and other matters, including safety requirements. On May 21, 2010 the Obama Administration announced proposed regulations that would set mileage requirements and emissions limits for medium- and heavy-duty trucks. A final rule is expected by July 30, 2011 effective for the 2014 model year. Associated with this ruling, we may experience an increase in costs related to truck purchases or maintenance. Proposals to increase federal, state, or local taxes, including taxes on motor fuels, are also made from time to time, and any such increase would increase our operating costs. We cannot predict whether, or in what form, any legislative or regulatory changes applicable to our trucking operations will be enacted.

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

As of December 31, 2010, our long-term debt, including current maturities, was $650 million. Our level of indebtedness may adversely affect operations and limit our growth, and we may have difficulty making debt service payments on our indebtedness as such payments become due. Our level of indebtedness may affect our operations in several ways, including the following:

- our vulnerability to general adverse economic and industry conditions;
- the covenants that are contained in the agreements that govern our indebtedness limit our ability to borrow funds, dispose of assets, pay dividends and make certain investments;
- any failure to comply with the financial or other covenants of our debt could result in an event of default, which could result in some or all of our indebtedness becoming immediately due and payable; and
- our level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or other general corporate purposes.

We may not be able to provide services that meet the specific needs of oil and gas exploration and production companies at competitive prices.

The markets in which we operate are highly competitive and have relatively few barriers to entry. The principal competitive factors in our markets are product and service quality and availability, responsiveness, experience, technology, equipment quality, reputation for safety and price. We compete with large national and multi-national companies that have longer operating histories, greater financial, technical and other resources and greater name recognition than we do. Several of our competitors provide a broader array of services and have a stronger presence in more geographic markets. In addition, we compete with several smaller companies capable of competing effectively on a regional or local basis. Our competitors may be able to respond more quickly to new or emerging technologies and services and changes in customer requirements. Some contracts are awarded on a bid basis, which further increases competition based on price. As a result of competition, we may lose market share or be unable to maintain or increase prices for our present services or to participate in additional business opportunities, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. In addition, competition among oilfield service and equipment providers is affected by each provider's reputation for safety and quality. Although we believe that our reputation for safety and quality service is good, we cannot assure that we will be able to maintain our competitive position.

Our executive officers and certain key personnel are critical to our business and these officers and key personnel may not remain with us in the future.

Our future success depends upon the continued service of our executive officers and other key personnel. If we lose the services of one or more of our executive officers or key employees, our business, operating results and financial condition could be harmed.

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

Acquisitions have been, and our management believes acquisitions will continue to be, a key element of our business strategy. We may not be able to identify and acquire acceptable acquisition candidates on favorable terms in the future. We may be required to incur substantial indebtedness to finance future acquisitions and also may issue equity securities in connection with such acquisitions. We may not be able to secure additional capital to fund acquisitions. If we are able to obtain financing, such additional debt service requirements may impose a significant burden on our results of operations and financial condition. The issuance of additional equity securities could result in significant dilution to stockholders. Acquisitions may not perform as expected when the acquisition was made and may be dilutive to our overall operating results. Additional risks we will face include:

- retaining and attracting key employees;
- retaining and attracting new customers;
- increased administrative burden;
- developing our sales and marketing capabilities;
- managing our growth effectively;
- integrating operations;
- operating a new line of business; and
- increased logistical problems common to large, expansive operations.

If we fail to manage these risks successfully, our business could be harmed.

Our customer base is concentrated within the oil and gas production industry and loss of a significant customer could cause our revenue to decline substantially.

Our top five customers accounted for approximately 39%, 33% and 28% of our revenue for the years ended December 31, 2010, 2009 and 2008, respectively. Our top ten customers represented approximately 52%, 49% and 45% of our revenue for the years then ended. Our top two customers provided 12.2% and 10.7% of our total annual revenue in 2010, and these same two customers provided 9.9% and 9.7% of our total annual revenue in 2009. It is likely that we will continue to derive a significant portion of our revenue from a relatively small number of customers in the future. If a major customer decided not to continue to use our services, revenue would decline and our operating results and financial condition could be harmed. For a list of our top ten customers, see Item 1. "Business — Customers."

We may be unable to attract and retain a sufficient number of skilled and qualified workers.

The delivery of our services and products requires personnel with specialized skills and experience who can perform physically demanding work. As a result of the volatility of the oilfield service industry and the demanding nature of the work, workers may choose to pursue employment in fields that offer a more desirable work environment. Our ability to be productive and profitable will depend upon our ability to employ and retain skilled workers. In addition, our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers is high, and the supply is limited, particularly in the U.S. Rocky Mountain region, which is one of our key regions. In addition, although our employees in the United States are not covered by a collective bargaining agreement, some of our employees have in the past been targeted by labor unions in an effort to organize such employees. A significant increase in the wages paid by competing employers or the unionization of groups of our employees could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

Our operations are subject to hazards inherent in the oil and gas industry.

Risks inherent to our industry, such as equipment defects, vehicle accidents, explosions and uncontrollable flows of gas or well fluids, can cause personal injury, loss of life, suspension of operations, damage to formations, damage to facilities, business interruption and damage to or destruction of property, equipment and the environment. These risks could expose us to substantial liability for personal injury, wrongful death, property damage, loss of oil and gas production, pollution and other environmental damages. The frequency and severity of such incidents will affect operating costs, insurability and relationships with customers, employees and regulators. In particular, our customers may elect not to purchase our services if they view our safety record as unacceptable, which could cause us to lose customers and substantial revenues. In addition, these risks may be greater for us because we sometimes acquire companies that have not allocated significant resources and management focus to safety and have a poor safety record.

Our operations have experienced fatalities. Many of the claims filed against us arise from vehicle-related accidents that have in certain specific instances resulted in the loss of life or serious bodily injury. Our safety procedures may not always prevent such damages. Our insurance coverage may be inadequate to cover our liabilities. In addition, we may not be able to maintain adequate insurance in the future at rates we consider reasonable and commercially justifiable and insurance may not continue to be available on terms as favorable as our current arrangements. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations and cash flows. Although our senior management is committed to improving our overall safety record, they may not be successful in doing so.

If we are not able to implement commercially competitive services and access commercially competitive products in a timely manner in response to changes in technology, our business and revenue could be materially and adversely affected.

The market for our services and products is characterized by continual technological developments to provide better and more reliable performance and services. If we are not able to implement commercially competitive services and access commercially competitive products in a timely manner in response to changes in technology, our business and revenue could be materially and adversely affected. Likewise, if our proprietary technologies, equipment and facilities, or work processes become obsolete, we may no longer be competitive, and our business and revenue could be materially and adversely affected.

We are self-insured for certain health care benefits for our employees.

We are self-insured for claims arising from healthcare benefits provided to certain of our employees in the United States. Under this self-insurance program, we use the services of an insurance company, the former provider of full insurance coverage prior to the inception of the program in 2007, to administer the program on a fee-per-participant basis, and we have purchased a stop-loss policy with this provider to insure for individual claims which exceed a designated ceiling. Pursuant to this program, we accrue expense based upon expected claims, and make periodic claim payments to the administrator, who then facilitates claim payments to the medical care providers. With the passage of time and as our business expands and more employees enroll in our healthcare benefit plan, we may choose or be required to maintain higher self-insured retention levels. There is a risk that our actual claims incurred may exceed the projected claims, and we may incur more expense than expected for health insurance coverage. There is also a risk that we may not adequately accrue for claims that are incurred but not reported. Either of these events could have a material adverse effect on our financial position, results of operations or cash flows.

If we become subject to product liability claims, it could be time-consuming and costly to defend.

Since our customers use our products, or third party products that we sell or rent, errors, defects or other performance problems could result in financial or other damages to us. Our customers could seek damages from us for losses associated with these errors, defects or other performance problems. If successful, these claims could have a material adverse effect on our business, operating results or financial condition. Our existing product liability insurance may not be enough to cover the full amount of any loss we might suffer. A product liability claim brought against us, even if unsuccessful, could be time-consuming and costly to defend and could harm our reputation.

Impairment of Long-term Assets

We evaluate our long-term assets including property, plant and equipment, identifiable intangible assets and goodwill in accordance with generally accepted accounting principles in the U.S. In performing this assessment, we project future cash flows on a discounted basis for goodwill, and on an undiscounted basis for other long-term assets, and compare these cash flows to the carrying amount of the related net assets. The cash flow projections are based on our current operating plan, estimates and judgmental assessments. We perform this assessment of potential impairment at least annually, but also whenever facts and circumstances indicate that the carrying value of the net assets may not be recoverable due to various external or internal factors, termed a "triggering event." We have recorded goodwill impairment charges of $97.6 million and $272.0 million for the years ended December 31, 2009 and 2008, respectively, with no goodwill impairment charges for the year ended December 31, 2010. In 2009, management performed additional analysis and determined that further write-downs were necessary, which resulted in a fixed asset impairment in our drilling services segment of $36.2 million recorded in September 2009, and an intangible asset impairment in our completion and production services segment totaling $2.5 million recorded in December 2009. Based on our annual impairment test results in 2010, we did not record any significant impairment losses for the year ended December 31, 2010. While we did not incur impairment charges in 2010, if we determine that our estimates of future cash flows were inaccurate or our actual results for 2011 are materially different than expected, we could record additional impairment charges at interim periods during 2011 or in future years, which could have a material adverse effect on our financial position and results of operations.

Many of our customers' activity levels, spending for our products and services, and payment patterns may be impacted by deterioration in the credit markets.

Many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. In late 2008 and throughout 2009, there was a significant decline in the credit markets and the availability of credit. Additionally, many of our customers' equity values substantially declined. The combination of a reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' spending for our products and services. A prolonged reduction in spending could have a material adverse effect on our operations.

In addition, while historically our customer base has not presented significant credit risks, the same factors that may lead to a reduction in our customers' spending also may increase our exposure to the risks of nonpayment and nonperformance by our customers. A significant reduction in our customers' liquidity may result in a decrease in their ability to pay or otherwise perform on their obligations to us. Any increase in the nonpayment of and nonperformance by our counterparties, either as a result of recent changes in financial and economic conditions or otherwise, could have an adverse impact on our operating results and could adversely affect our liquidity.

We participate in a capital intensive business. We may not be able to finance future growth of our operations or future acquisitions.

Historically, we have funded the growth of our operations and our acquisitions from bank debt, private placement of shares, our initial public offering in April 2006, a private placement of debt in December 2006, as well as cash generated by our business. In the future, we may not be able to continue to obtain sufficient bank debt at competitive rates or complete equity and other debt financings. If we do not generate sufficient cash from our business to fund operations, our growth could be limited unless we are able to obtain additional capital through equity or debt financings. Our inability to grow as planned may reduce our chances of maintaining and improving profitability.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud.

Effective internal controls are necessary for us to provide reliable financial reports and effectively prevent fraud. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. Our efforts to maintain internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective controls or to make effective improvements to our internal controls could harm our operating results.

In 2010, our management approved a plan to implement new accounting software which will replace our existing accounting systems at several of our operating divisions in a phased approach. Two divisions converted during the fourth quarter of 2010 and two divisions will convert during 2011. In addition, we implemented a new chart of accounts which is being adopted as these divisions convert to the new software. Although we believe the new software, once implemented, will enhance our internal control over financial reporting and we believe that we have taken the necessary steps to maintain appropriate internal control over financial reporting during this period of system change, we will continuously monitor controls through and around the system to provide reasonable assurance that controls are effective during and after each step of this implementation process.

Conservation measures and technological advances could reduce demand for oil and gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and gas. Management cannot predict the impact of the changing demand for oil and gas services and products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Fluctuations in currency exchange rates in Canada could adversely affect our business.

We have operations in Canada. As a result, fluctuations in currency exchange rates in Canada could materially and adversely affect our business. For each of the years ended December 31, 2010, 2009 and 2008, our Canadian operations represented approximately 5% of our revenue from continuing operations. Our Canadian operations recorded income from continuing operations before taxes of $1.3 million for the year ended December 31, 2010 and recorded losses of $11.1 million and $26.7 million for the years ended December 31, 2009 and 2008, respectively. The loss in 2008 primarily resulted from a goodwill impairment charge.

Our operations in Mexico are subject to specific risks, including dependence on Petróleos Mexicanos ("PEMEX") as the primary customer, exposure to fluctuation in the Mexican peso and workforce unionization.

The majority of our business in Mexico is performed for PEMEX pursuant to multi-year contracts. These contracts are generally two years in duration, specify an authorized spending amount and are subject to competitive bid for renewal. Any failure by us to renew or extend our existing contracts, or win award of contracts that replace expiring contracts, could have an adverse effect on our financial condition, results of operations and cash flows. Additionally, PEMEX is experiencing budget limitations that may affect its ability to make timely payments to us under our existing contracts. Recent regulatory and financial uncertainty regarding PEMEX's drilling programs and development budget could adversely impact PEMEX's ability to fulfill certain of its payment obligations under these contracts in a timely manner. A failure of PEMEX to make required payments to us would adversely affect our Mexico-based financial performance.

The PEMEX contracts provide that 70% to 80% of the value of our billings under the contracts is charged to PEMEX in U.S. dollars with the remainder billed in Mexican pesos. The portion billed in U.S. dollars to PEMEX is converted to pesos on the date of payment. Invoices are paid approximately 45 days after the invoice date. As such, we are exposed to fluctuations in the value of the peso. A material decrease in the value of the Mexican peso relative to the U.S. dollar could negatively impact our revenues, cash flows and net income.

Our operations in Mexico are party to a collective labor contract most recently modified on and effective as of October 2008 between Servicios Petrotec S.A. DE C.V., one of our subsidiaries, and Unión Sindical de Trabajadores de la Industria Metálica y Similares, the metal and similar industry workers labor union. We have not experienced work stoppages in the past but cannot guarantee that we will not experience work stoppages in the future. A prolonged work stoppage could negatively impact our revenues, cash flows and net income.

Mexico has experienced a period of increasing criminal violence and such activities could affect our Mexico-based operations and financial performance.

Recently, Mexico has experienced a period of increasing criminal violence, primarily due to the activities of drug cartels and related organized crime. Although the Mexican government has implemented various security measures and strengthened its military and police forces, drug-related crime continues to exist in Mexico and has impacted our ability to safely conduct business in certain areas of the country. Our inability to conduct business in certain areas of Mexico, and the safety risks in the areas of Mexico where we do conduct business, could have a negative impact on our Mexico-based financial performance.

We could be adversely affected by violations of the U.S. Foreign Corrupt Practices Act and similar worldwide anti-bribery laws.

We are subject to the U.S. Foreign Corrupt Practices Act (the "FCPA"), which generally prohibits companies and their intermediaries from making payments to non-U.S. government officials for the purpose of obtaining or retaining business or securing any other improper advantage. We are also subject to anti-bribery laws in the jurisdictions in which we operate. Although we have policies and procedures designed to ensure that we, our employees and our agents comply with the FCPA and other anti-bribery laws, there is no assurance that such policies or procedures will protect us against liability under the FCPA or other laws for actions taken by our agents, employees and intermediaries with respect to our business or any businesses that we acquire. We do business in countries in which FCPA violations have recently been enforced. Failure to comply with the FCPA, other anti-bribery laws or other laws governing the conduct of business with foreign government entities, including local laws, could disrupt our business and lead to severe criminal and civil penalties, including imprisonment, criminal and civil fines, loss of our export licenses and suspension of our ability to do business with the federal government. Other remedial measures could include further changes or enhancements to our procedures, policies, and controls and potential personnel changes and/or disciplinary actions, any of which could have a material adverse affect on our business, financial condition, results of operations and liquidity. We could also be adversely affected by any allegation that we violated such laws.

Severe weather conditions may affect our operations.

Our business may be materially affected by severe weather conditions in areas where we operate. This may entail the evacuation of personnel and stoppage of services which could adversely affect our financial condition, results of operations and cash flows. Hurricanes and the threat of hurricanes during this period will often result in the shut-down of oil and gas operations in the Gulf of Mexico as well as land operations within the hurricane path. During a shut-down period, we are unable to access wellsites and our services are also shut down. This situation can therefore create unpredictability in activity and utilization rates, which can have a material adverse impact on our business, financial conditions, results of operations and cash flows. In addition, the extreme winter weather conditions in the first quarter of 2011 have adversely affected our operations in North Dakota, Oklahoma and North Texas.

Our operations are directly affected by seasonal differences in weather in Canada. The level of activity in the Canadian oilfield services industry declines significantly in the second calendar quarter, when the ground thaws and many secondary roads are temporarily rendered incapable of supporting the weight of heavy equipment. The duration of this period is referred to as "spring breakup" and has a direct impact on our activity levels in Canada. The timing and duration of "spring breakup" depend on weather patterns but generally "spring breakup" occurs in April and May. Additionally, if an unseasonably warm winter prevents sufficient freezing, we may not be able to access wellsites and our operating results and financial condition may, therefore, be adversely affected. The demand for our services may also be affected by the severity of the Canadian winters. In addition, during excessively rainy periods, equipment moves may be delayed, thereby adversely affecting operating results. The volatility in weather and temperature in the Canadian oilfield can therefore create unpredictability in activity and utilization rates. As a result, full-year results are not likely to be a direct multiple of any particular quarter or combination of quarters.

When rig counts are low, our rig relocation customers may not have a need for our services.

Many of the major U.S. onshore drilling services contractors have capabilities to move their own drilling rigs and related oilfield equipment and to erect rigs. When regional rig counts are high, drilling services contractors exceed their own capabilities and contract for additional oilfield equipment hauling and rig erection capacity. Our rig relocation business activity is highly correlated to the rig count; however, the correlation varies over the rig count range. As rig count drops, some drilling services contractors reach a point where all of their oilfield equipment hauling and rig erection needs can be met by their own fleets. If one or more of our rig relocation customers reaches this "tipping point," our revenues attributable to rig relocation will decline much faster than the corresponding overall decline in the rig count. This non-linear relationship between our rig relocation business activity and the rig count in the areas in which we have rig relocation operations can significantly increase our earnings volatility with respect to rig relocation.

Covenants in our debt agreements restrict our business in many ways.

The indenture governing our senior notes contains various covenants that limit our ability and/or our restricted subsidiaries' ability to, among other things:

- incur or assume liens or additional debt or provide guarantees in respect of obligations of other persons;
- issue redeemable stock and certain preferred stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase subordinated debt;
- make loans and investments;
- enter into agreements that restrict distributions from our subsidiaries;
- sell assets and capital stock of our subsidiaries;
- enter into certain transactions with affiliates;
- consolidate or merge with or into, or sell substantially all of our assets to, another person; and
- enter into new lines of business.

In addition, our amended revolving credit facility contains restrictive covenants and requires us to maintain a fixed charge coverage ratio based on borrowing base limitations and satisfy other financial condition tests. Our ability to meet those financial requirements can be affected by adverse industry conditions and other events beyond our control, and we cannot assure you that we will meet those requirements. A breach of any of these covenants could result in a default under our amended revolving credit facility and/or the notes. Upon the occurrence of an event of default under our amended revolving credit facility, the lenders could elect to declare all amounts outstanding to be immediately due and payable and terminate all commitments to extend further credit. We had no borrowings outstanding under our amended credit facility at December 31, 2010. However, if we borrowed under this facility and if we were unable to repay those amounts, the lenders under our amended revolving credit facility could proceed against the collateral granted to them to secure that indebtedness. We have pledged a significant portion of our assets as collateral under our amended revolving credit facility. If the lenders under our amended revolving credit facility accelerate the repayment of borrowings, we cannot assure you that we will have sufficient assets to repay indebtedness under our amended revolving credit facility and our other indebtedness, including our senior notes.

Borrowings under our amended revolving credit facility would bear interest at variable rates and could expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase even though the amount borrowed remained the same, and our net income would decrease.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

As of December 31, 2010, we owned 57 offices, facilities and yards, of which 15 were in Texas, 18 were in Oklahoma, one was in Arkansas, three were in North Dakota, one was in Montana, one was in Wyoming, 10 were in Colorado, one was in Louisiana, three were in Pennsylvania, two were in Alberta, Canada, one was in Poza Rica, Mexico and one was in Singapore.

As of December 31, 2010, we owned or operated 64 saltwater disposal wells, of which 29 were in Texas, 32 were in Oklahoma, two were in Colorado, and one was in Arkansas. In addition, we owned one and leased two drilling mud disposal facilities in Oklahoma and one produced water evaporation facility in Wyoming.

In addition, as of December 31, 2010, we leased 209 offices, facilities and yards, of which 74 were in Texas, 25 were in Oklahoma, 18 were in Wyoming, 25 were in Colorado, 22 were in Pennsylvania, three were in North Dakota, 10 were in Louisiana, three were in Arkansas, two were in Utah, 14 were in Alberta, Canada, one was in British Columbia, Canada, six were in Mexico and six were in Singapore.

We lease our corporate headquarters in Houston, Texas, as well as administrative offices in Gainesville, Texas; Enid, Oklahoma; Fredrick, Colorado; Eunice, Louisiana; Shelocta, Pennsylvania; Calgary, Alberta, Canada; and additional office space in Houston, Texas.

Item 3. ***Legal Proceedings.***

In the normal course of our business, we are a party to various pending or threatened claims, lawsuits and administrative proceedings seeking damages or other remedies concerning our commercial operations, products, employees and other matters, including warranty and product liability claims and occasional claims by individuals alleging exposure to hazardous materials, on the job injuries and fatalities as a result of our products or operations. Many of the claims filed against us relate to motor vehicle accidents which can result in the loss of life or serious bodily injury. Some of these claims relate to matters occurring prior to our acquisition of businesses. In certain cases, we are entitled to indemnification from the sellers of such businesses.

Although we cannot know or predict with certainty the outcome of any claim or proceeding or the effect such outcomes may have on us, we believe that any liability resulting from the resolution of any of these matters, to the extent not otherwise provided for or covered by insurance, will not have a material adverse effect on our financial position, results of operations or liquidity.

We have historically incurred additional insurance premium related to a cost-sharing provision of our general liability insurance policy, and we cannot be certain that we will not incur additional costs until either existing claims become further developed or until the limitation periods expire for each respective policy year. Any such additional premiums should not have a material adverse effect on our financial position, results of operations or liquidity.

Item 4. ***(Removed and Reserved)***

PART II

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

At February 14, 2011, we had 78,592,455 shares of common stock outstanding, of which 1,353,996 shares were non-vested restricted stock subject to forfeiture restrictions. The common shares outstanding at February 14, 2011 were held by 57 record holders, excluding stockholders for whom shares are held in "nominee" or "street" name. We had 5,000,000 authorized shares of $0.01 par value preferred stock, of which none was issued and outstanding at December 31, 2010 or February 14, 2011.

On April 21, 2006, our common stock began trading on the New York Stock Exchange under the symbol "CPX." On April 26, 2006, we completed our initial public offering.

The following table presents the high and low sales prices of our common stock reported on the New York Stock Exchange for each of the calendar quarters in 2009 and 2010:

Period	CPX Stock Price High	CPX Stock Price Low
Quarter ended March 31, 2009	$10.10	$ 2.32
Quarter ended June 30, 2009	$ 8.31	$ 3.27
Quarter ended September 30, 2009	$11.72	$ 6.78
Quarter ended December 31, 2009	$13.48	$ 9.11
Quarter ended March 31, 2010	$16.06	$10.83
Quarter ended June 30, 2010	$15.97	$11.33
Quarter ended September 30, 2010	$21.69	$13.68
Quarter ended December 31, 2010	$32.72	$20.52

The year-end closing sales price of our common stock was $13.00 on December 31, 2009, the last trading day of 2009, and $29.55 on December 31, 2010, the last trading day of 2010.

Issuer Purchases of Equity Securities:

In accordance with the provisions of the 2008 Incentive Award Plan, holders of unvested restricted stock were given the option to either remit to us the required withholding taxes associated with the vesting of restricted stock, or to authorize us to repurchase shares equivalent to the cost of the withholding tax and to remit the withholding taxes on behalf of the holder. We made no repurchases of our common stock during the year ended December 31, 2008. However, pursuant to this provision, we repurchased 18,743 shares in 2009 and 113,330 shares in 2010, of which the following shares were purchased during the quarter ended December 31, 2010:

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 — 31, 2010	—	—	—	*
November 1 — 30, 2010	—	—	—	*
December 1 — 31, 2010	436	29.00	436	*

* We do not have a publicly announced stock repurchase program. We had 1,672,854 shares of non-vested restricted stock outstanding at December 31, 2010. The holders of these shares have the option to either remit taxes due related to the vesting of these shares or to authorize us to purchase the shares at the current market value in a sufficient amount to settle the related tax withholding. The amount purchased will depend on the market value at the time and whether or not the holders choose to surrender shares in settlement of the related tax withholding.

Equity Compensation Plans:

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" contained herein.

Dividends:

We paid no dividends on our outstanding $0.01 par value common stock for the years ended December 31, 2010, 2009 or 2008. We currently do not intend to pay dividends in the foreseeable future, but rather plan to reinvest such funds in our business. Furthermore, our credit facility and the indenture governing our senior notes contain covenants which restrict us from paying future dividends on our common stock.

Performance Graph:

The information in this section of the Annual Report pertaining to our performance relative to our peers is being furnished but not filed with the SEC, and as such, the information is neither subject to Regulation 14A or 14C or to the liabilities of Section 18 of the Exchange Act of 1934.

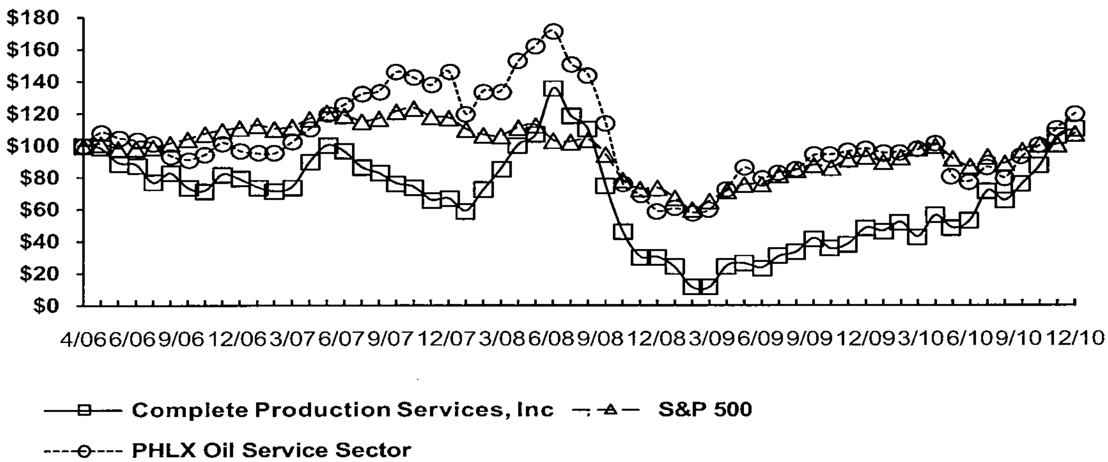
The following chart presents a comparative analysis of the stock performance of our common stock ("CPX") relative to an industry index, the Philadelphia Oil Service Sector Index ("OSX"), and a broader market index, Standard & Poor's 500 Index ("S&P"). This analysis assumes a $100 investment in the underlying common stock of CPX, OSX and S&P on April 21, 2006, the date of our initial public offering, through December 31, 2010. This analysis does not purport to be a representation of the actual market performance of our stock or these indexes. This chart has been provided for informational purposes to assist the reader in evaluating the market performance of our common stock compared to other market participants.

Notwithstanding anything to the contrary set forth in our previous filings under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, which might incorporate future filings made by us under those statutes, the following Stock Performance Graph will not be deemed incorporated by reference into any future filings made by us under those statutes.

COMPARISON OF 56 MONTH CUMULATIVE TOTAL RETURN*

Among Complete Production Services, Inc, the S&P 500 Index

And The PHLX Oil Service Sector Index



* $100 invested on 4/21/06 in stock or 3/31/06 in index, including reinvestment of dividends. Fiscal year ending December 31.

Item 6. ***Selected Financial Data.***

The following table presents selected historical consolidated financial and operating data for the periods shown. The selected consolidated financial data as of December 31, 2006, 2007, 2008, 2009 and 2010 and for each of the years then ended have been derived from our audited consolidated financial statements for those dates and periods, adjusted for discontinued operations, as indicated. The following information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our financial statements and related notes included elsewhere in this Annual Report.

	For the Year Ended December 31,				
	2006	2007	2008	2009	2010
			(In thousands)		
Statement of Operations Data:					
Revenue:					
Completion and production services	$ 860,508	$1,238,126	$1,541,709	$ 897,584	$1,354,797
Drilling services	194,517	212,272	234,104	114,729	172,821
Products sales	29,586	40,857	59,102	44,081	33,775
Total	1,084,611	1,491,255	1,834,915	1,056,394	1,561,393
Expenses:					
Service and product expenses(1)	630,195	875,570	1,136,488	725,365	1,011,040
Selling, general and administrative	144,503	179,508	198,200	181,420	175,445
Depreciation and amortization	75,902	131,399	181,197	200,732	181,823
Fixed asset and other intangibles impairment loss(2)	—	—	—	38,646	—
Goodwill impairment loss(2)	—	13,094	272,006	97,643	—
Operating income from continuing operations before interest, taxes and non-controlling interest	234,011	291,684	47,024	(187,412)	193,085
Write-off of deferred financing fees	170	—	—	528	—
Interest expense	40,645	61,328	59,729	56,895	57,669
Interest income	(1,387)	(325)	(301)	(79)	(322)
Taxes	70,184	84,833	72,305	(63,088)	51,580
Income (loss) from continuing operations before non-controlling interest	124,399	145,848	(84,709)	(181,668)	84,158
Non-controlling interest	(49)	(569)	—	—	—
Income (loss) from continuing operations	124,448	146,417	(84,709)	(181,668)	84,158
Income (loss) from discontinued operations (net of tax expense of $9,359, $6,890, $3,865, $0 and $0, respectively)(3)	14,050	11,443	(4,859)	—	—
Net income (loss)	$ 138,498	$ 157,860	$ (89,568)	$ (181,668)	$ 84,158
Income (loss) from continuing operations per diluted share	$ 1.83	$ 2.00	$ (1.15)	$ (2.42)	$ 1.08

(1) Service and product expenses is the aggregate of service expenses and product expenses.

(2) For the year ended December 31, 2009, we recorded a fixed asset impairment in our drilling services segment of $36,158 and an intangible asset impairment in our completion and production services segment totaling $2,488. We also recorded a goodwill impairment charge of $97,643 associated with several of our reportable units at December 31, 2009. We recorded an impairment loss of $272,006 associated with goodwill for various reporting units as of December 31, 2008. For the year ended December 31, 2007, we recorded an impairment

loss of $13,094 associated with our Canadian reporting unit. For a further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this Annual Report.

(3) In May 2008, our Board of Directors authorized and committed to a plan to sell certain operations in the Barnett Shale region of north Texas, consisting primarily of our supply store business, as well as certain non-strategic drilling logistics assets and other completion and production services assets. On May 19, 2008, we sold these operations to a company owned by a former officer of one of our subsidiaries. In August 2006, our Board of Directors authorized and committed to a plan to sell certain manufacturing and production enhancement product sales operations of a subsidiary located in Alberta, Canada, which includes certain assets located in south Texas. This sale was completed on October 31, 2006. We revised our financial statements and reclassified the assets and liabilities of these disposal groups as held for sale as of the date of each balance sheet presented and removed the results of operations of the disposal group from net income from continuing operations, and presented these separately as income (loss) from discontinued operations, net of tax, for each of the accompanying statements of operations. We ceased depreciating the assets when each disposal group was reclassified as held for sale, and we adjusted the net assets to the lower of carrying value or fair value less selling costs. For a further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included elsewhere in this Annual Report.

	For the Year Ended December 31,				
	2006	2007	2008	2009	2010
			(In thousands)		
Other Financial Data:					
Adjusted EBITDA(4)	$ 309,743	$ 436,177	$ 500,227	$ 149,081	$ 374,908
Cash flows from operating activities	187,635	338,415	350,409	285,204	216,158
Cash flows from financing activities	471,376	66,643	27,990	(207,991)	(174,088)
Cash flows from investing activities	(650,863)	(409,189)	(374,098)	(18,128)	6,817
Capital expenditures:					
Acquisitions, net of cash acquired(5)	369,606	50,406	180,154	—	33,721
Property, plant and equipment	303,922	368,053	253,776	38,487	169,919

	As of December 31,				
	2006	2007	2008	2009	2010
			(In thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 19,766	$ 13,034	$ 18,500	$ 77,360	$ 126,681
Net property, plant and equipment	752,648	1,013,539	1,166,686	941,133	956,028
Goodwill	541,313	549,130	341,592	243,823	250,533
Total assets	1,739,198	2,050,633	1,987,353	1,588,854	1,800,576
Long-term debt, excluding current portion	750,311	825,985	843,842	650,002	650,000
Total stockholders' equity	734,633	926,031	860,711	698,890	805,834

(4) Adjusted EBITDA consists of net income (loss) from continuing operations before net interest expense, taxes, depreciation and amortization, non-controlling interest and impairment loss. Adjusted EBITDA is a non-GAAP measure of performance. We use Adjusted EBITDA as the primary internal management measure for evaluating performance and allocating additional resources. The calculation of Adjusted EBITDA is different from the calculation of "EBITDA," as defined and used in our credit facilities. For a discussion of the calculation of "EBITDA" as defined under our existing credit facilities, as recently amended, see Note 11,

"Long-term debt" in the Notes to Consolidated Financial Statements. Adjusted EBITDA is included in this Annual Report on Form 10-K because our management considers it an important supplemental measure of our performance and believes that it is frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry, some of which present EBITDA when reporting their results. We regularly evaluate our performance as compared to other companies in our industry that have different financing and capital structures and/or tax rates by using Adjusted EBITDA. In addition, we use Adjusted EBITDA in evaluating acquisition targets. Management also believes that Adjusted EBITDA is a useful tool for measuring our ability to meet our future debt service, capital expenditures and working capital requirements, and Adjusted EBITDA is commonly used by us and our investors to measure our ability to service indebtedness. Adjusted EBITDA is not a substitute for the GAAP measures of earnings or cash flow and is not necessarily a measure of our ability to fund our cash needs. In addition, it should be noted that companies calculate EBITDA differently and, therefore, EBITDA has material limitations as a performance measure because it excludes interest expense, taxes, depreciation and amortization and non-controlling interest. The following table reconciles Adjusted EBITDA with our net income (loss).

(5) Acquisitions, net of cash acquired, consists only of the cash component of acquisitions. It does not include common stock and notes issued for acquisitions, nor does it include other non-cash assets issued for acquisitions.

Reconciliation of Adjusted EBITDA

	For the Year Ended December 31,				
	2006	2007	2008	2009	2010
			(In thousands)		
Net income (loss)	$138,498	$157,860	$ (89,568)	$(181,668)	$ 84,158
Plus: interest expense, net	39,258	61,003	59,428	56,816	57,347
Plus: tax expense (benefit)	70,184	84,833	72,305	(63,088)	51,580
Plus: depreciation and amortization	75,902	131,399	181,197	200,732	181,823
Plus: non-controlling interest	(49)	(569)	—	—	—
Plus: impairment loss	—	13,094	272,006	136,289	—
Minus: income (loss) from discontinued operations (net of tax expense of $9,359, $6,890, $3,865, $0 and $0, respectively)	14,050	11,443	(4,859)	—	—
Adjusted EBITDA	$309,743	$436,177	$500,227	$ 149,081	$374,908

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included within this Annual Report. This discussion contains forward-looking statements based on our current expectations, assumptions, estimates and projections about us and the oil and gas industry. See "Forward-Looking Statement" contained in Item 1. "Business." These forward-looking statements involve risks and uncertainties that may be outside of our control and could cause actual results to differ materially from those in the forward-looking statements. For examples of those risks and uncertainties, see the cautionary statements contained in Item 1A. "Risk Factors." Factors that could cause or contribute to such differences include, but are not limited to: market prices for oil and gas, the level of oil and gas drilling, economic and competitive conditions, capital expenditures, regulatory changes and other uncertainties. In light of these risks, uncertainties and assumptions, the forward-looking events discussed below may not occur. Unless otherwise required by law, we undertake no obligation to publicly update any forward-looking statements, even if new information becomes available or other events occur in the future.

The words "believe," "may," "will," "estimate," "continue," "anticipate," "intend," "plan," "expect" 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.

Overview

We are a leading provider of specialized completion and production services and products focused on helping oil and gas companies develop hydrocarbon reserves, reduce operating costs and enhance production. We focus on basins within North America that we believe have attractive long-term potential for growth, and we deliver targeted, value-added services and products required by our customers within each specific basin. We believe our range of services and products positions us to meet the many needs of our customers at the wellsite, from drilling and completion through production and eventual abandonment. We manage our operations from regional field service facilities located throughout the U.S. Rocky Mountain region, Texas, Oklahoma, Louisiana, Arkansas, Pennsylvania, western Canada, Mexico and Southeast Asia.

We operate in three business segments:

Completion and Production Services. Through our completion and production services segment, we establish, maintain and enhance the flow of oil and gas throughout the life of a well. This segment is divided into the following primary service lines:

- *Intervention Services.* Well intervention requires the use of specialized equipment to perform an array of wellbore services. Our fleet of intervention service equipment includes coiled tubing units, pressure pumping units, nitrogen units, well service rigs, snubbing units and a variety of support equipment. Our intervention services provide customers with innovative solutions to increase production of oil and gas.

- *Downhole and Wellsite Services.* Our downhole and wellsite services include electric-line, slickline, production optimization, production testing, rental and fishing services.

- *Fluid Handling.* We provide a variety of services to help our customers obtain, move, store and dispose of fluids that are involved in the development and production of their reservoirs. Through our fleet of specialized trucks, frac tanks and other assets, we provide fluid transportation, heating, pumping and disposal services for our customers.

Drilling Services. Through our drilling services segment, we provide services and equipment that initiate or stimulate oil and gas production by providing land drilling and specialized rig logistics services.

Product Sales. We provide oilfield service equipment and refurbishment of used equipment through our Southeast Asian business, and we provide repair work and fabrication services for our customers at a business located in Gainesville, Texas.

Substantially all service and rental revenue we earn is based upon a charge for a period of time (an hour, a day, a week) for the actual period of time the service or rental is provided to our customer, on a fixed per-stage-completed fee or pursuant to a long-term contract which may include take-or-pay provisions. Product sales are recorded when the actual sale occurs and title or ownership passes to the customer.

Our customers include large multi-national and independent oil and gas producers, as well as smaller independent producers and the major land-based drilling contractors in North America (see "Customers" in Item 1 of this Annual Report on Form 10-K). The primary factors influencing demand for our services and products are the level of drilling and workover activity of our customers and the complexity of such activity, which in turn, depends on current and anticipated future oil and gas prices, production depletion rates and the resultant levels of cash flows generated and allocated by our customers to their drilling and workover budgets. As a result, demand for our services and products is cyclical, substantially depends on activity levels in the North American oil and gas industry and is highly sensitive to current and expected oil and natural gas prices. The following tables summarize average North American drilling and well service rig activity, as measured by Baker Hughes Incorporated ("BHI") and the

Cameron International Corporation/Guiberson/AESC Service Rig Count for "Active Rigs," respectively, and historical commodity prices as provided by Bloomberg:

AVERAGE RIG COUNTS

	Year Ended				
	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10
BHI Rotary Rig Count:					
U.S. Land	1,559	1,695	1,814	1,046	1,514
U.S. Offshore	90	73	65	44	31
Total U.S.	1,649	1,768	1,879	1,090	1,545
Canada	471	343	382	222	348
Total North America	2,120	2,111	2,261	1,312	1,893

Source: BHI *(www.BakerHughes.com)*

	Year Ended				
	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10
Cameron International Corporation/Guiberson/AESC Well Service Rig Count (Active Rigs):					
United States	2,364	2,388	2,515	1,722	1,854
Canada	779	596	686	457	534
Total U.S. and Canada	3,143	2,984	3,201	2,179	2,388

Source: Cameron International Corporation/Guiberson/AESC Well Service Rig Count for "Active Rigs."

Service rig counts for active rigs for December 2010 was 2,682 according to the Cameron International Corporation/Guiberson/AESC Well Service Rig Count for "Active Rigs" and was 2,713 as of January 31, 2011.

AVERAGE OIL AND GAS PRICES

Period	Average Daily Closing Henry Hub Spot Natural Gas Prices ($/mcf)	Average Daily Closing WTI Cushing Spot Oil Price ($/bbl)
1/1/01 — 12/31/01	$3.99	$25.96
1/1/02 — 12/31/02	3.37	26.17
1/1/03 — 12/31/03	5.49	31.06
1/1/04 — 12/31/04	5.90	41.51
1/1/05 — 12/31/05	8.89	56.56
1/1/06 — 12/31/06	6.73	66.09
1/1/07 — 12/31/07	6.97	72.23
1/1/08 — 12/31/08	8.89	99.92
1/1/09 — 12/31/09	3.94	61.99
1/1/10 — 12/31/10	4.38	79.48

Source: Bloomberg NYMEX prices.

The closing spot price of a barrel of WTI Cushing oil at December 31, 2010 was $91.38 and the closing spot price for Henry Hub natural gas ($/mcf) was $4.41. At February 14, 2011, the closing spot price of a barrel of WTI Cushing oil was $84.81 and the closing spot price for Henry Hub natural gas was $3.92.

We consider the drilling and well service rig counts to be an indication of spending by our customers in the oil and gas industry for exploration and development of new and existing hydrocarbon reserves. These spending levels are a primary driver of our business, and we believe that our customers tend to invest more in these activities when oil and gas prices are at higher levels or are increasing. The utilization of our assets and the performance of our business can be impacted by these and other external and internal factors. See Item 1A. "Risk Factors."

We generally charge for our services either on a dayrate or per-stage-completed basis. Depending on the specific service, charges may include one or more of these components: (1) a set-up charge, (2) an hourly service rate based on equipment and labor, (3) a stage-completed charge, (4) an equipment rental charge, (5) a consumables charge, and (6) a mileage and fuel charge. We generally determine the rates charged through a competitive process on a job-by-job basis. Typically, work is performed on a "call out" basis, whereby the customer requests services on a job-specific basis, but does not guarantee work levels beyond the specific job bid. For contract drilling services, fees are charged based on standard dayrates or, to a lesser extent, as negotiated by footage contracts. Product sales generated through our Southeast Asian business are typically based on a pre-determined price book.

We have entered into long-term take or pay contracts on the majority of our pressure pumping capacity. These agreements are typically for three-year terms and require our customers to pay us a minimum daily rate for not less than five days per week and provide for an option to operate seven days per week. We are typically paid within 30 — 60 days for services provided during the previous month. The contracts typically provide incentives to compensate us for better efficiencies and services provided at higher pressures, extended pump times and flow rates. We are also able to pass-through increases in costs associated with certain consumables used in pressure pumping operations. Our customers would be required to pay us substantial fees for the early termination of the contracts.

Outlook

Our growth strategy is focused on internal growth in the basins in which we currently operate, maximizing equipment utilization, adding additional like-kind equipment and expanding our service and product offerings. We seek new basins in which to replicate this approach and augment our internal growth with strategic acquisitions. Our business is impacted by changes in the oil and gas cycle. Oil and gas commodity prices rose steadily throughout the decade culminating in 2008, then declined sharply in late 2008 and the early part of 2009, primarily due to the global financial crisis. Oil prices recovered through the remainder of 2009 and continued a gradual improvement during the course of 2010 along with the global economy. The price of natural gas in North America has remained subdued as a result of storage levels remaining above historical averages caused primarily by increasing gas production from unconventional resource plays. As a result, exploration and production companies are shifting a greater portion of their activities into emerging oil and liquid-rich plays and our business has shifted from a predominantly gas-oriented business, to a majority oil and liquids-oriented business.

In 2010, we remained disciplined with our financial investments in capital expenditures, targeted specific acquisitions, which were additive to our business objectives and responded to our customers' needs for quality services in the emerging oil and liquid-rich plays. We redeployed equipment and personnel into the emerging basins while continuing to maintain a strong presence in our historical markets.

- *Internal Capital Investment.* Our internal expansion activities have generally consisted of adding equipment and qualified personnel in locations where we have established a presence. We have grown our operations in many of these locations by expanding services to current customers, attracting new customers and hiring local personnel with local basin-level expertise and leadership recognition. Depending on customer demand, we will consider adding equipment to further increase the capacity of services currently being provided and/or add equipment to expand the services we provide. We invested $462.2 million in equipment additions over the three-year period ended December 31, 2010, which included $399.4 million for the completion and production services segment, $51.9 million for the drilling services segment, $6.8 million for the product sales segment and $4.1 million related to general corporate operations. For the year ended December 31, 2010, we invested $169.9 million in capital expenditures.
- *External Growth.* We use strategic acquisitions as an integral part of our growth strategy. We consider acquisitions that will add to our service offerings in a current operating area or that will expand our geographical footprint into a targeted basin. We have completed several acquisitions in recent years. These

acquisitions affect our operating performance from period to period. Accordingly, revenue and operating results in different periods are not necessarily comparable and should not be relied upon as indications of future performance. We invested an aggregate of $213.9 million in acquisitions over the three-year period ended December 31, 2010. Of this amount, we invested an aggregate of $33.7 million to acquire 3 businesses during 2010, including a well servicing platform acquisition in the Eagle Ford Shale of south Texas, and $180.2 million to acquire 4 businesses during 2008. We did not complete any business acquisitions during the year ended December 31, 2009. See "— Significant Transactions."

For 2011, we anticipate that activity levels will remain strong and a greater percentage of activity will be directed at increasingly more service intensive, multi-stage, horizontal wells. Current oil prices are encouraging increased investments in oil plays and in gas fields that have meaningful natural gas liquids content. Additionally, drilling and completion activity required to retain leases and service capacity shortages, which have led to a backlog of wells to be completed, should support activity in dry gas basins through the first half of the year.

As a result of our positive outlook for North America in 2011 we have expanded our capital expenditure program which includes: (1) roughly 170,000 hydraulic horse power of pressure pumping equipment; (2) five larger-diameter coiled tubing units with extended reach capabilities; and (3) meaningful investments in fluid handling and well servicing assets. Additionally, we continue to seek strategic acquisitions to enhance service offerings and extend our presence in new service areas.

We, and many of our competitors, are investing in new equipment, some of which requires long lead-times to manufacture. As more of this equipment is available to be placed into service there could be additional excess capacity in the industry, which may negatively impact utilization rates and pricing and put inflationary pressure on labor costs. To improve efficiencies for us and our customers and due to the concern associated with excess capacity we have entered into long-term take-or-pay contracts on the majority of our pressure pumping capacity. Additionally, we continue to monitor our equipment utilization and poll our customers to assess demand levels. As equipment enters the marketplace or competition for existing customers increases, we believe our customers will rely upon service providers who provide quality services and have positioned themselves to be responsive to customer's needs which we believe we have and which constitutes a fundamental aspect of our growth strategy.

Our business continues to be impacted by seasonality and inclement weather, including the effects of harsh winter weather conditions which occurred during the past few months in North Dakota, Oklahoma and north Texas, the normal second quarter Canadian "break-up," as well as the impact of Gulf of Mexico tropical weather systems.

We believe our customers will continue to rely upon service providers with local knowledge and a proven ability to effectively execute complex services on more service intensive, longer-lateral horizontal wells, particularly in oil and liquid-rich basins. We believe we are well positioned in high-growth basins and our core services, which include pressure pumping, coiled tubing, well servicing and fluid handling, will benefit from these secular trends.

Significant Transactions

During 2010, we acquired substantially all the assets or all of the equity interests in three oilfield service companies, for $33.7 million in cash, resulting in goodwill of approximately $6.9 million.

- On May 11, 2010, we acquired certain assets of a provider of gas lift services based in Oklahoma City, Oklahoma. The total purchase price for the assets was $1.4 million in cash. We recorded goodwill totaling $1.0 million in conjunction with this acquisition which has been allocated entirely to the completion and production services business segment. We believe this acquisition supplements our plunger lift service offering for the completion and production services business segment.

- On September 3, 2010, we purchased the assets of a well service and fluid handling service provider based in Carrizo Springs, Texas. The total purchase price for the assets was $20.8 million and included goodwill of $4.9 million, all of which was allocated to the completion and production services business segment. We believe this acquisition enhances our position in the Eagle Ford Shale in south Texas.

- On December 1, 2010, we acquired all of the outstanding common stock of a disposal well operator located in Colorado for $12.6 million in cash, subject to an additional $0.5 million holdback. We recorded goodwill totaling $1.5 million in conjunction with this acquisition which has been allocated entirely to the completion and production services business segment. We believe this acquisition will enhance our position in the Denver-Julesburg Basin in Colorado.

During 2008, we acquired substantially all the assets or all of the equity interests in four oilfield service companies, for $180.2 million in cash, resulting in goodwill of approximately $71.2 million.

- On February 29, 2008, we acquired substantially all of the assets of KR Fishing & Rental, Inc. for $9.5 million in cash, resulting in goodwill of $6.4 million. KR Fishing & Rental, Inc. is a provider of fishing, rental and foam unit services in the Piceance Basin and the Raton Basin, and is located in Rangely, Colorado. We believe this acquisition complemented our completion and production services business in the Rocky Mountain region.

- On April 15, 2008, we acquired all the outstanding common stock of Frac Source Services, Inc., a provider of pressure pumping services to customers in the Barnett Shale of north Texas, for $62.4 million in cash, net of cash acquired, which includes a working capital adjustment of $1.6 million, and recorded goodwill of $15.4 million. Upon closing this transaction, we entered into a contract with one of our major customers to provide pressure pumping services in the Barnett Shale utilizing three frac fleets under a contract with a term that extends up to three years from the date each fleet is placed into service. We spent an additional $20.0 million in 2008 on capital equipment related to these contracted frac fleets. Thus, our total investment in this operation was approximately $82.4 million. We believe this acquisition expanded our pressure pumping business in north Texas and that the related contract provided a stable revenue stream from which to expand our pressure pumping business outside of this region.

- On October 3, 2008, we acquired all of the membership interests of TSWS Well Services, LLC, a limited liability corporation which held substantially all of the well servicing and heavy haul assets of TSWS, Inc., a company based in Magnolia, Arkansas, which provides well servicing and heavy haul services to customers in northern Louisiana, east Texas and southern Arkansas. As consideration, we paid $57.2 million in cash and prepaid an additional $1.0 million related to an employee retention bonus pool. We also recorded goodwill totaling $21.9 million. We believe this acquisition extended our geographic reach into the Haynesville Shale area.

- On October 4, 2008, we acquired substantially all of the assets of Appalachian Well Services, Inc. and its wholly-owned subsidiary, each of which is based in Shelocta, Pennsylvania. This business provides pressure pumping, e-line and coiled tubing services in the Appalachian region, and includes a service area which extends through portions of Pennsylvania, West Virginia, Ohio and New York. As consideration for the purchase, we paid $50.1 million in cash and issued 588,292 unregistered shares of our common stock, valued at $15.04 per share. We invested an additional $6.5 million to complete a frac fleet at this location and have an option to purchase real property for approximately $0.6 million. In addition, we entered into an agreement that could have required us to pay up to an additional $5.0 million in cash consideration during the earn-out period. This earn-out period ended in 2010 with no additional consideration paid. We recorded goodwill of approximately $27.5 million associated with this acquisition, however, this goodwill was deemed impaired in 2009 and expensed as of December 31, 2009. This acquisition created a platform for future growth for our pressure pumping and other completion and production service lines in the Marcellus Shale.

We have accounted for our acquisitions using the purchase method of accounting, whereby the purchase price is allocated to the fair value of net assets acquired, including intangibles and property, plant and equipment at depreciated replacement costs with the excess to goodwill. Results of operations related to each of the acquired companies have been included in our accounts and results of operations as of the date of acquisition.

In March 2009, our Canadian subsidiary exchanged certain non-monetary assets with a net book value of $9.3 million related to our production testing business for certain e-line assets of a competitor. We recorded a non-cash loss on the transaction of $4.9 million, which represented the difference between the carrying value and the fair market value of the assets surrendered. We believe the e-line assets will generate incremental future cash flows compared to the production testing assets exchanged.

In May 2008, our Board of Directors authorized and committed to a plan to sell certain operations in the Barnett Shale region of north Texas, consisting primarily of our supply store business, as well as certain non-strategic drilling logistics assets and other completion and production services assets. On May 19, 2008, we sold these operations to Select Energy Services, L.L.C., a company owned by a former officer of one of our subsidiaries, for which we received proceeds of $50.2 million in cash and assets with a fair market value of $8.0 million. The carrying value of the net assets sold was approximately $51.4 million, excluding $11.1 million of allocated goodwill associated with the combination that formed Complete Production Services, Inc. in September 2005. We recorded a loss on the sale of this disposal group totaling approximately $6.9 million, which included $2.6 million related to income taxes. In accordance with the sales agreement, we sublet office space to Select Energy Services, L.L.C. and provided certain administrative services for an initial term of one year, at an agreed-upon rate.

On October 31, 2006, we completed the sale of a disposal group which included certain manufacturing and production enhancement operations of a subsidiary located in Alberta, Canada, as well as operations in south Texas. We sold this disposal group to an oilfield service company located in Calgary, Alberta, Canada. In conjunction with this asset disposal, the buyer issued a note to us for $2.0 million denominated in Canadian dollars. During the second quarter of 2010, we were notified that the seller was in default on a term loan and security agreement which was senior to our note. Therefore, management recorded a provision of $1.9 million for bad debt associated with this note as of June 30, 2010, but we will continue to pursue our interest in this note to the extent a portion may be recoverable in a future period.

Market Environment

We operate in a highly competitive industry. Our competition includes many large and small oilfield service companies. As such, we price our services and products to remain competitive in the markets in which we operate, adjusting our rates to reflect current market conditions as necessary. We examine the rate of utilization of our equipment as one measure of our ability to compete in the current market environment.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with Generally Accepted Accounting Principles ("GAAP") requires the use of estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, and provide a basis for making judgments about the carrying value of assets and liabilities that are not readily available through open market quotes. Estimates and assumptions are reviewed periodically, and actual results may differ from those estimates under different assumptions or conditions. We must use our judgment related to uncertainties in order to make these estimates and assumptions.

In the selection of our critical accounting policies, the objective is to properly reflect our financial position and results of operations for each reporting period in a consistent manner that can be understood by the reader of our financial statements. Our accounting policies and procedures are explained in Note 2, "Significant accounting policies," in our notes to consolidated financial statements included elsewhere in this Annual Report. We consider an estimate to be critical if it is subjective and if changes in the estimate using different assumptions would result in a material impact on our financial position or results of operations.

We have identified the following as the most critical accounting policies and estimates, and have provided: (1) a description, (2) information about variability and (3) our historical experience, including a sensitivity analysis, if applicable.

Revenue Recognition

We recognize service revenue as services are performed and when realized or earned. Revenue is deemed to be realized or earned when we determine that the following criteria are met: (1) persuasive evidence of an arrangement exists; (2) delivery has occurred or services have been rendered; (3) the fee is fixed or determinable; and (4) collectibility is reasonably assured. These services are generally provided over a relatively short period of time pursuant to short-term contracts at pre-determined dayrate fees, or on a day-to-day basis. Revenue and costs related to drilling contracts are recognized as work progresses. Progress is measured as revenue is recognized based upon dayrate charges. For certain contracts, we may receive lump-sum payments from our customers related to the mobilization of rigs and other drilling equipment. Under these arrangements, we defer revenues and the related cost of services and recognize them over the term of the drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Revenues associated with product sales are recorded when product title is transferred to the customer.

Under current GAAP, revenue is to be recognized when it is realized or realizable and earned. The SEC's rules and regulations provide additional guidance for revenue recognition under specific circumstances, including bill and hold transactions. There is a risk that our results of operations could be misstated if we do not record revenue in the proper accounting period.

The nature of our business has been such that we generally bill for services over a relatively short period of time or bill for services on a stage-completed basis under a longer-term contract with take-or-pay provisions and record revenues as products are sold. We did not record material adjustments resulting from revenue recognition issues for the years ended December 31, 2010, 2009 and 2008.

Impairment of Long-Lived Assets

Based on guidance from the Financial Accounting Standards Board ("FASB") regarding accounting for the impairment or disposal of long-lived assets, we evaluate potential impairment of long-lived assets and intangibles, excluding goodwill and other intangible assets without defined service lives, when indicators of impairment are present. If such indicators are present, we project the fair value of the assets by estimating the undiscounted future cash in-flows to be derived from the long-lived assets over their remaining estimated useful lives, as well as any salvage value. Then, we compare this fair value estimate to the carrying value of the assets and determine whether the assets are deemed to be impaired. For goodwill and other intangible assets without defined service lives, we perform an annual impairment test, whereby we estimate the fair value of the asset by discounting future cash flows at a projected cost of capital rate. If the fair value estimate is less than the carrying value of the asset, an additional test is required whereby we apply a purchase price analysis similar to a purchase price allocation for a business combination. If impairment is still indicated, we would record an impairment loss in the current reporting period for the amount by which the carrying value of the intangible asset exceeds its projected fair value.

Our industry is highly cyclical and the estimate of future cash flows requires the use of assumptions and our judgment. Periods of prolonged down cycles in the industry could have a significant impact on the carrying value of these assets and may result in impairment charges. If our estimates do not approximate actual performance or if the rates we used to discount cash flows vary significantly from actual discount rates, we could overstate our assets and an impairment loss may not be timely identified.

We tested goodwill for impairment for each of the years ended December 31, 2010, 2009 and 2008. Management prepared a discounted cash flow analysis to determine the fair market value of the reportable units as of the annual testing date. Projected cash flows were based on certain management assumptions related to expected growth, capital investment and terminal value, discounted at a market-participant weighted average cost of capital, refined to reflect our current and anticipated capital structure. Based on this analysis, management determined that goodwill was not impaired as of our annual testing date in 2010, but was impaired in 2009 and 2008. In accordance with the FASB's guidance for goodwill, management performed a step-two analysis to calculate the amount by which the carrying value of the reporting units exceeded the projected fair market value of such units as of the respective annual testing dates. We performed our impairment calculations as of December 31, 2008, incorporating our assumptions of future earnings and cash flows. Based on this testing, we determined that the goodwill associated with most of our reporting units had been impaired. We recorded an impairment charge of $272.0 million at December 31, 2008. In calculating this impairment charge, management made assumptions about future earnings by reportable unit, which may differ from actual future earnings for these operations. In 2009, management performed additional analysis and determined that further write-downs were necessary. We recorded a goodwill impairment charge of $97.6 million associated with several of our reportable units at December 31, 2009. In addition, pursuant to an undiscounted cash flow analysis, we recorded a fixed asset impairment in our drilling services segment of $36.2 million and an intangible asset impairment in our completion and production services segment totaling $2.5 million during 2009. A significant decline in expected future cash flow, a further erosion of market conditions or a lower-than-expected recovery of the oil and gas industry activity levels in future years, could result in an additional impairment charge.

Stock Options and Other Stock-Based Compensation

We have issued stock-based compensation to certain employees, officers and directors in the form of stock options and restricted stock. In accordance with U.S. GAAP, we account for grants made prior to September 30, 2005, the date of our initial filing with the SEC, using the minimum value method, whereby no compensation expense is recognized for stock-based compensation grants that have an exercise price equal to the fair value of the stock on the date of grant. For grants of stock-based compensation between October 1, 2005 and December 31, 2005, we utilized the modified prospective transition method to record expense associated with these options, whereby we did not record compensation expense associated with these grants during the period October 1, 2005 through December 31, 2005 but provided pro forma disclosure of this expense, and, then began recognizing compensation expense related to these grants over the remaining vesting period after December 31, 2005 based upon a calculated fair value. These grants were fully vested as of December 31, 2009. For grants of stock-based compensation on or after January 1, 2006, we recognize expense associated with new awards of stock-based compensation, as determined using a Black-Scholes pricing model over the expected term of the award. In addition, we record compensation expense associated with restricted stock which has been granted to certain of our directors, officers and employees. In accordance with current U.S. GAAP, we calculate compensation expense on the date of grant (number of options granted multiplied by the fair value of our common stock on the date of grant) and recognize this expense, adjusted for forfeitures, ratably over the applicable vesting period.

U.S. GAAP permits the use of various models to determine the fair value of stock options and the variables used for the model are highly subjective. For purposes of determining compensation expense associated with stock options granted after January 1, 2006, we are required to determine the fair value of the stock options by applying a pricing model which includes assumptions for expected term, discount rate, stock volatility, expected forfeitures and a dividend rate. The use of different assumptions or a different model may have a material impact on our financial disclosures.

For the years ended December 31, 2010, 2009 and 2008, we applied a Black-Scholes model with similar assumptions for expected term (based on a probability analysis and ranging from 2.2 to 5.1 years), risk free rate (based upon published rates for U.S. Treasury notes), zero dividend rate and stock volatility, which we determined based on our historical common stock volatility for grants after June 2008 and estimated based on the historical volatility rates of several peer companies prior to that time. In addition, we estimated a forfeiture rate based upon our historical experience. We have recorded compensation expense associated with stock option and restricted stock grants totaling $11.6 million, $12.2 million and $12.4 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Allowance for Bad Debts and Inventory Obsolescence

We record trade accounts receivable at billed amounts, less an allowance for bad debts. Inventory is recorded at cost, less an allowance for obsolescence. To estimate these allowances, management reviews the underlying details of these assets as well as known trends in the marketplace, and applies historical factors as a basis for recording these allowances. If market conditions are less favorable than those projected by management, or if our historical experience is materially different from future experience, additional allowances may be required.

There is a risk that management may not detect uncollectible accounts or unsalvageable inventory in the correct accounting period.

Bad debt expense (recovery) has been less than 1% of sales for the years ended December 31, 2010, 2009 and 2008. If bad debt expense had increased by 1% of sales, net income would have decreased by $9.7 million for the year ended December 31, 2010 and net loss would have increased by $7.8 million and $11.9 million for the years ended December 2009 and 2008, respectively. Our obsolescence and other inventory reserves were approximately 7%, 2% and 2% of our inventory balances at December 31, 2010, 2009 and 2008, respectively. A 1% increase in inventory reserves, from 7% to 8%, at December 31, 2010 would have decreased net income by $0.2 million for the year then ended.

Property, Plant and Equipment

We record property, plant and equipment at cost less accumulated depreciation. Major betterments to existing assets are capitalized, while repairs and maintenance costs that do not extend the service lives of our equipment are expensed. We determine the useful lives of our depreciable assets based upon historical experience and the judgment of our operating personnel. We generally depreciate the historical cost of assets, less an estimate of the applicable salvage value, on the straight-line basis over the applicable useful lives. Upon disposition or retirement of an asset, we record a gain or loss if the proceeds from the transaction differ from the net book value of the asset at the time of the disposition or retirement.

U.S. GAAP permits various depreciation methods to recognize the use of assets. Use of a different depreciation method or different depreciable lives could result in materially different results. If our depreciation estimates are not correct, we could over- or understate our results of operations, such as recording a disproportionate amount of gains or losses upon disposition of assets. There is also a risk that the useful lives we apply for our depreciation calculation will not approximate the actual useful life of the asset. We believe our estimates of useful lives are materially correct and that these estimates are consistent with industry averages.

We evaluate property, plant and equipment for impairment when there are indicators of impairment. We did not record any significant impairment charges related to our long-term assets for the year ended December 31, 2010. During September 2009, we evaluated the fair market value of assets in our contract drilling business with the assistance of a third-party appraiser and determined that the carrying value of certain of these drilling rigs exceeded the fair market value estimates. We projected the undiscounted cash flows associated with these rigs, including an estimate of salvage value, and compared these expected future cash flows to the carrying amount of the rigs. If the undiscounted cash flows exceeded the carrying amount, no further testing was performed and the rig was deemed to not be impaired. If the undiscounted cash flows did not exceed the carrying value, we estimated the fair market value of the equipment based on management estimates and general market data obtained by the third-party appraiser using the sales comparison market approach, which included the analysis of recent sales and offering prices of similar equipment to arrive at an indication of the most probable net sales proceeds for the equipment. The result of this analysis was a calculated fixed asset impairment of $36.2 million, which was recorded as an impairment loss in September 30, 2009. This impairment charge was allocated entirely to the drilling services business segment. This impairment was deemed necessary due to an overall decline in oil and gas exploration and production activity in late 2008 which extended throughout 2009, as well as management's expectation of future operating results for this business segment. There were no significant impairment charges related to our long-term assets during the year ended December 31, 2008. Depreciation and amortization expense for the years ended December 31, 2010 and 2009 represented 19% of the average depreciable asset base for each year. An increase in depreciation expense relative to the depreciable base of 1%, from 19% to 20%, would have reduced net income by approximately $5.9 million for the year ended December 31, 2010.

Self Insurance

On January 1, 2007, we began a self-insurance program to pay claims associated with health care benefits provided to certain of our employees in the United States. Pursuant to this program, we have purchased a stop-loss insurance policy from an insurance company. Our accounting policy for this self-insurance program is to accrue expense based upon the number of employees enrolled in the plan at pre-determined rates. As claims are processed and paid, we compare our claims history to our expected claims in order to estimate incurred but not reported claims. If our estimate of claims incurred but not reported exceeds our current accrual, we record additional expense during the current period. There is a risk that we may not estimate our incurred but not reported claims correctly or that our stop-loss provision may not be adequate to insure us against losses in the future. At December 31, 2010, we accrued $4.7 million pursuant to this self-insurance program. A 10% increase in this self-insurance accrual would reduce our net income for the year ended December 31, 2010 by $0.4 million.

Deferred Income Taxes

Our income tax expense includes income taxes related to the United States, Canada and other foreign countries, including local, state and provincial income taxes. We account for tax ramifications pursuant to U.S. GAAP for income taxes and record deferred income tax assets and liabilities based upon temporary differences between the carrying amount and tax basis of our assets and liabilities and measure tax expense using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates is recognized in income in the period of the change. Furthermore, we record a valuation allowance for any deferred income tax assets which we believe are likely to not be used through future operations. As of December 31, 2010, 2009 and 2008, we recorded a valuation allowance of less than $1.0 million related to certain deferred tax assets in Canada. If our estimates and assumptions related to our deferred tax position change in the future, we may be required to record additional valuation allowances against our deferred tax assets and our effective tax rate may increase, which could adversely affect our financial results. As of December 31, 2010, we did not provide deferred U.S. income taxes on approximately $28.6 million of undistributed earnings of our foreign subsidiaries in which we intend to indefinitely reinvest. Upon distribution of these earnings in the form of dividends or otherwise, we may be subject to U.S. income taxes and foreign withholding taxes. On January 1, 2007, we adopted the FASB interpretation that provides guidance to account for uncertain tax positions. Annually, we perform an evaluation of our tax positions. We have evaluated our tax positions at December 31, 2010 and believe these positions are deemed appropriate for all significant matters.

There is a risk that estimates related to the use of loss carry forwards and the realizability of deferred tax accounts may be incorrect, and that the result could materially impact our financial position and results of operations. In addition, future changes in tax laws or GAAP requirements could result in additional valuation allowances or the recognition of additional tax liabilities.

Historically, we have utilized net operating loss carry forwards to partially offset current tax expense, and we have recorded a valuation allowance to the extent we expect that our deferred tax assets will not be utilized through future operations. Deferred income tax assets totaled $30.5 million at December 31, 2010, against which we recorded a valuation allowance of $0.3 million, leaving a net deferred tax asset of $30.2 million deemed realizable. Changes in our valuation allowance would affect our net income on a dollar for dollar basis.

Discontinued Operations

We account for discontinued operations in accordance with the FASB guidance on accounting for the impairment or disposal of long-lived assets. U.S. GAAP requires that we classify the assets and liabilities of a disposal group as held for sale if the following criteria are met: (1) management, with appropriate authority, commits to a plan to sell a disposal group; (2) the asset is available for immediate sale in its current condition; (3) an active program to locate a buyer and other actions to complete the sale have been initiated; (4) the sale is probable; (5) the disposal group is being actively marketed for sale at a reasonable price; and (6) actions required to complete the plan of sale indicate it is unlikely that significant changes to the plan of sale will occur or that the plan will be withdrawn. Once deemed held for sale, we no longer depreciate the assets of the disposal group. Upon sale, we calculate the gain or loss associated with the disposition by comparing the carrying value of the assets less direct costs of the sale with the proceeds received. In conjunction with the sale, we settle inter-company balances between us and the disposal group and allocate interest expense to the disposal group for the period the assets were held for sale. In the statement of operations, we present discontinued operations, net of tax effect, as a separate caption below net income from continuing operations.

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

The following tables set forth our results of continuing operations, including amounts expressed as a percentage of total revenue, for the periods indicated (in thousands, except percentages).

	Year Ended 12/31/10	Year Ended 12/31/09	Change 2010/ 2009	Percent Change 2010/ 2009
		(In thousands)		
Revenue:				
Completion and production services	$1,354,797	$ 897,584	$457,213	51%
Drilling services	172,821	114,729	58,092	51%
Product sales	33,775	44,081	(10,306)	(23)%
Total	$1,561,393	$1,056,394	$504,999	48%
Adjusted EBITDA:				
Completion and production services	$ 369,826	$ 165,787	$204,039	123%
Drilling services	38,973	9,641	29,332	304%
Product sales	5,197	7,966	(2,769)	(35)%
Corporate	(39,088)	(34,313)	(4,775)	(14)%
Total	$ 374,908	$ 149,081	$225,827	151%

"Corporate" includes amounts related to corporate personnel costs, other general expenses and stock-based compensation charges.

"Adjusted EBITDA" consists of net income (loss) from continuing operations before net interest expense, taxes, depreciation and amortization, non-controlling interest and impairment loss. Adjusted EBITDA is a non-GAAP measure of performance. We use Adjusted EBITDA as the primary internal management measure for evaluating performance and allocating additional resources. The following table reconciles Adjusted EBITDA for the years ended December 31, 2010 and 2009 to the most comparable U.S. GAAP measure, operating income (loss). The calculation of Adjusted EBITDA is different from the calculation of "EBITDA," as defined and used in our credit facilities. For a discussion of the calculation of "EBITDA" as defined under our existing credit facilities, as recently amended, see Note 11, "Long-term debt" in our notes to consolidated financial statements included elsewhere in this Annual Report.

Reconciliation of Adjusted EBITDA to Most Comparable GAAP Measure — Operating Income (Loss)

(In thousands)

Year Ended December 31, 2010	Completion and Production Services	Drilling Services	Product Sales	Corporate	Total
Adjusted EBITDA, as defined	$ 369,826	$ 38,973	$5,197	$(39,088)	$ 374,908
Depreciation and amortization	$ 159,110	$ 18,480	$2,211	$ 2,022	$ 181,823
Operating income (loss)	$ 210,716	$ 20,493	$2,986	$(41,110)	$ 193,085
Year Ended December 31, 2009					
Adjusted EBITDA, as defined	$ 165,787	$ 9,641	$7,966	$(34,313)	$ 149,081
Depreciation and amortization	$ 174,929	$ 21,067	$2,460	$ 2,276	$ 200,732
Write-off of deferred financing fees	$ —	$ —	$ —	$ (528)	$ (528)
Fixed asset and other intangible impairment loss	$ 2,488	$ 36,158	$ —	$ —	$ 38,646
Goodwill impairment loss	$ 97,643	$ —	$ —	$ —	$ 97,643
Operating income (loss)	$(109,273)	$(47,584)	$5,506	$(36,061)	$(187,412)

Reconciliation of Net Income (Loss) to Adjusted EBITDA

	For the Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Net income (loss)	$ 84,158	$(181,668)	$ (89,568)
Plus: interest expense, net	57,347	56,816	59,428
Plus: tax expense (benefit)	51,580	(63,088)	72,305
Plus: depreciation and amortization	181,823	200,732	181,197
Plus: impairment loss	—	136,289	272,006
Minus: income (loss) from discontinued operations (net of tax expense of $0, $0 and $3,865, respectively)	—	—	(4,859)
Adjusted EBITDA	$374,908	$ 149,081	$500,227

Below is a detailed discussion of our operating results by segment for these periods.

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

Revenue

Revenue from continuing operations for the year ended December 31, 2010 increased by $505.0 million, or 48%, to $1,561.4 million from $1,056.4 million for the year ended December 31, 2009. This increase by segment was as follows:

- *Completion and Production Services.* Segment revenue increased $457.2 million, or 51%, primarily due to an increase in demand for our services and an overall increase in activity levels for the oil and gas industry during 2010 compared to 2009, resulting in higher utilization of our equipment. Activity levels and pricing in some service lines and select geographic areas began to improve during the latter part of the fourth quarter of 2009 and continued improving throughout 2010. The segment continued to benefit from increased horizontal drilling and completion related activity within resource plays, particularly for our pressure pumping, fluid handling and U.S. coiled tubing businesses, Our pressure pumping business also benefitted from the deployment of approximately 43,000 hydraulic horse power of new pressure pumping equipment into the Eagle Ford and Bakken shales during the latter part of 2010.

- *Drilling Services.* Segment revenue increased $58.1 million, or 51%, for the year, primarily due to improved utilization and pricing in our rig relocation and contract drilling businesses. The rig relocation business also benefitted from long rig moves as customers reactivated and repositioned assets from dry gas basins into emerging oil and liquid-rich markets such as the Bakken, Niobrara and Eagle Ford shales.

- *Product Sales.* Segment revenue decreased $10.3 million, or 23%, for the year, primarily due to lower third-party sales at our repair and fabrication shop in north Texas as several large projects were completed during the first quarter of 2009, while results for our Southeast Asian business remained relatively constant for the years ended December 31, 2010 and 2009.

Service and Product Expenses

Service and product expenses include labor costs associated with the execution and support of our services, materials used in the performance of those services and other costs directly related to the support and maintenance of equipment. These expenses increased $285.7 million, or 39%, to $1,011.0 million for the year ended December 31, 2010 from $725.4 million for the year ended December 31, 2009. The increase in service and product expenses was consistent with an overall increase in revenues resulting from improvements in oilfield activity in the

U.S. and Canada in 2010. The following table summarizes service and product expenses as a percentage of revenues for the years ended December 31, 2010 and 2009:

Service and Product Expenses as a Percentage of Revenue

Segment:	Years Ended 12/31/10	Years Ended 12/31/09	Change
Completion and Production services	64%	68%	(4)%
Drilling services	70%	75%	(5)%
Product sales	77%	75%	2%
Total	65%	69%	(4)%

Service and product expenses as a percentage of revenue improved to 65% for the year ended December 31, 2010 compared to 69% for the year ended December 31, 2009. Margins by business segment were impacted primarily by utilization and pricing.

- *Completion and Production Services.* Service and product expenses as a percentage of revenue for this business segment decreased when comparing the year ended December 31, 2010 to the same period in 2009. The year-over-year favorable margin improvement was attributable to an increase in overall oilfield activity, improved pricing and service mix, with an increase in sales for historically higher-margin offerings, partially offset by some increases in labor costs and other inflationary factors. We enacted certain cost-saving measures in 2009, including headcount reductions and payroll concessions which were substantially reinstated during 2010.
- *Drilling Services.* The decrease in service and product expenses as a percentage of revenue for this business segment was primarily due to increased asset utilization and improved pricing.
- *Product Sales.* The increase in service and product expenses as a percentage of revenue for the products segments was primarily due to the mix of products sold for the relative periods. Additionally, on a year-over-year basis, a larger proportion of the revenues and related costs for the product sales segment for the year ended December 31, 2010 were provided by our Southeast Asian business, for which sales tend to be project specific and are subject to fluctuations in activity levels in the region.

Selling, General and Administrative Expenses

Selling, general and administrative expenses include salaries and other related expenses for our selling, administrative, finance, information technology and human resource functions. Selling, general and administrative expenses decreased $6.0 million, or 3%, to $175.4 million for the year ended December 31, 2010 from $181.4 million for the year ended December 31, 2009. The results for 2009 included incremental bad debt charges associated with specifically-identified uncollectible accounts of $10.9 million, incremental losses on the retirement of fixed assets of $12.8 million and certain insignificant inventory adjustments. In addition, we recorded a loss on the non-monetary exchange of certain assets in Canada during the first quarter of 2009 which totaled $4.9 million. The overall decrease in selling, general and administrative expense in 2010 was partially offset by higher incentive compensation based on earnings, increased payroll costs, higher insurance costs and the write-off of a $1.9 million note receivable in Canada. Excluding the impact of the non-monetary asset exchange in Canada, the incremental charges to bad debt expense and losses on the retirement of fixed assets, as a percentage of revenues, selling, general and administrative expense was 11% and 14% for the years ended December 31, 2010 and 2009, respectively.

Depreciation and Amortization

Depreciation and amortization expense decreased $18.9 million, or 9%, to $181.8 million for the year ended December 31, 2010 from $200.7 million for the year ended December 31, 2009. The decrease in depreciation and amortization expense was attributable to the normal run-off of depreciation associated with existing assets, asset retirements in 2009, a $36.2 million impairment of our drilling rigs as of September 30, 2009, sale-leaseback transactions associated with our small vehicle fleet as well as a facility in Wyoming and an impairment charge in late 2009 related to certain intangible assets acquired in 2008. Although we increased our capital expenditures in 2010 compared to 2009, approximately half of those additions were incurred during the second half of the year, resulting in overall lower depreciation and amortization expense year-over-year. As a percentage of revenue, depreciation and amortization expense decreased to 12% from 19% for the years ended December 31, 2010 and 2009, respectively.

Fixed Asset and Other Intangible Impairment Loss

We did not record any impairment charges in 2010. For the year ended December 31, 2009, we recorded a fixed asset and other intangible impairment loss of $38.6 million. We recorded a charge of $36.2 million related to our contract drilling business in the third quarter of 2009 after determining that the carrying value of certain of these drilling rigs exceeded the undiscounted cash flows associated with these assets and the fair market value estimates for these assets. In the fourth quarter of 2009, we recorded an impairment of intangible assets of $2.5 million related to our completion and production business.

Goodwill Impairment Loss

We did not record any goodwill impairment in 2010. For the year ended December 31, 2009, we recorded a goodwill impairment loss of $97.6 million. The write-downs of goodwill was associated with several of our reporting units and was based upon several valuation techniques including a discounted cash flow analysis of expected future earnings associated with these businesses. Our analysis of future cash flows was impacted significantly by the overall decline in oilfield activity in late 2008 which continued throughout 2009.

Taxes

Tax expense (benefit) is comprised of current income taxes and deferred income taxes. The current and deferred taxes added together provide an indication of an effective rate of income tax.

We recorded a tax provision of $51.6 million, at an effective rate of 38%, for the year ended December 31, 2010 compared to a tax benefit of $63.1 million for the year ended December 31, 2009 at an effective rate of approximately 25.8%. The lower effective tax rate in 2009 was primarily due to the impairment of goodwill with limited tax basis. Excluding the impact of the goodwill impairment charges, our effective tax rate for the year ended December 31, 2009 would have been 33.9%.

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

The following tables set forth our results of continuing operations, including amounts expressed as a percentage of total revenue, for the periods indicated (in thousands, except percentages).

	Year Ended 12/31/09	Year Ended 12/31/08	Change 2009/ 2008	Percent Change 2009/ 2008
		(In thousands)		
Revenue:				
Completion and production services	$ 897,584	$1,541,709	$(644,125)	(42)%
Drilling services	114,729	234,104	(119,375)	(51)%
Product sales	44,081	59,102	(15,021)	(25)%
Total	$1,056,394	$1,834,915	$(778,521)	(42)%
Adjusted EBITDA:				
Completion and production services	$ 165,787	$ 467,100	$(301,313)	(65)%
Drilling services	9,641	58,743	(49,102)	(84)%
Product sales	7,966	12,677	(4,711)	(37)%
Corporate	(34,313)	(38,293)	3,980	10%
Total	$ 149,081	$ 500,227	$(351,146)	(70)%

"Corporate" includes amounts related to corporate personnel costs, other general expenses and stock-based compensation charges.

"Adjusted EBITDA" consists of net income (loss) from continuing operations before net interest expense, taxes, depreciation and amortization, non-controlling interest and impairment loss. Adjusted EBITDA is a non-GAAP measure of performance. We use Adjusted EBITDA as the primary internal management measure for evaluating performance and allocating additional resources. The following table reconciles Adjusted EBITDA for the years ended December 31, 2009 and 2008 to the most comparable U.S. GAAP measure, operating income (loss). The calculation of Adjusted EBITDA is different from the calculation of "EBITDA," as defined and used in our credit facilities. For a discussion of the calculation of "EBITDA" as defined under our existing credit facilities, as recently amended, see Note 11, "Long-term debt," in our notes to consolidated financial statements included elsewhere in this Annual Report.

Reconciliation of Adjusted EBITDA to Most Comparable GAAP Measure — Operating Income (Loss)

	Completion and Production Services	(In thousands) Drilling Services	Product Sales	Corporate	Total
Year Ended December 31, 2009					
Adjusted EBITDA, as defined	$ 165,787	$ 9,641	$ 7,966	$(34,313)	$ 149,081
Depreciation and amortization	$ 174,929	$ 21,067	$ 2,460	$ 2,276	$ 200,732
Write-off of deferred financing fees	$ —	$ —	$ —	$ (528)	$ (528)
Fixed asset and other intangible impairment losses	$ 2,488	$ 36,158	$ —	$ —	$ 38,646
Goodwill impairment loss	$ 97,643	$ —	$ —	$ —	$ 97,643
Operating income (loss)	$(109,273)	$(47,584)	$ 5,506	$(36,061)	$(187,412)
Year Ended December 31, 2008					
Adjusted EBITDA, as defined	$ 467,100	$ 58,743	$12,677	$(38,293)	$ 500,227
Depreciation and amortization	$ 156,298	$ 19,961	$ 2,537	$ 2,401	$ 181,197
Goodwill impairment losses	$ 243,203	$ 27,410	$ 1,393	$ —	$ 272,006
Operating income (loss)	$ 67,599	$ 11,372	$ 8,747	$(40,694)	$ 47,024

Below is a detailed discussion of our operating results by segment for these periods.

Year Ended December 31, 2009 Compared to the Year ended December 31, 2008

Revenue

Revenue from continuing operations for the year ended December 31, 2009 decreased by $778.5 million, or 42%, to $1,056.4 million from $1,834.9 million for the year ended December 31, 2008. This decrease by segment was as follows:

- *Completion and Production Services.* Segment revenue decreased $644.1 million, or 42%, primarily due to an overall decline in investment by our customers in oil and gas exploration and development activities resulting from lower oil and gas commodity prices and concerns over the availability of capital for such investment. We experienced lower utilization and pricing for each of our service offerings on a year-over-year basis, except for our coiled tubing business in Mexico which provided a positive contribution to 2009 results. In the fourth quarter of 2009, we experienced an increase in revenues and margins compared to the third quarter of 2009 as market conditions showed signs of improvement.

- *Drilling Services.* Segment revenue decreased $119.4 million, or 51%, for the year, primarily due to the overall decline in oilfield service activities throughout the year compared to 2008. Lower utilization rates and pricing pressure impacted our rig logistics and drilling businesses, however revenues were up slightly in the fourth quarter of 2009 compared to the third quarter of 2009 as we experienced a slight increase in customer activity.

- *Product Sales.* Segment revenue decreased $15.0 million, or 25%, for the year, primarily due to a decline in our Southeast Asian business resulting from a change in the sales mix and the timing of product sales and equipment refurbishment, which tends to be project-specific. Partially offsetting this decrease were the consistent revenues earned at our fabrication business in north Texas year-over-year, which included a workover rig project completed in the first quarter of 2009 and sales of low margin equipment to third-parties.

Service and Product Expenses

Service and product expenses include labor costs associated with the execution and support of our services, materials used in the performance of those services and other costs directly related to the support and maintenance of equipment. These expenses decreased $411.1 million, or 36%, to $725.4 million for the year ended December 31, 2009 from $1,136.5 million for the year ended December 31, 2008. The decline in service and product expenses was primarily due to significantly lower activity levels and cost-saving measures we began implementing in late 2008, including headcount reductions, payroll concessions and reduced product and service costs from outside vendors. The following table summarizes service and product expenses as a percentage of revenues for the years ended December 31, 2009 and 2008:

Service and Product Expenses as a Percentage of Revenue

	Years Ended		
Segment:	**12/31/09**	**12/31/08**	**Change**
Completion and Production services	68%	61%	7%
Drilling services	75%	67%	8%
Product sales	75%	71%	4%
Total	69%	62%	7%

Service and product expenses as a percentage of revenue increased to 69% for the year ended December 31, 2009 compared to 62% for the year ended December 31, 2008. Margins by business segment were impacted primarily by pricing and utilization.

- *Completion and Production Services.* Service and product expenses as a percentage of revenue for this business segment increased when comparing the year ended December 31, 2009 to the same period in 2008. The overall decline in activity levels in the oil and gas industry, which began in late 2008 and continued throughout most of the year in 2009, resulted in lower utilization of our equipment and services, and pricing pressure from competitors. Partially defraying the impact of this overall decline in activity levels were cost-saving measures we began implementing in late 2008.

- *Drilling Services.* The increase in service and product expenses as a percentage of revenue for this business segment was primarily due to lower utilization of our equipment due to significantly reduced activity levels by our customers, and lower pricing on a year-over-year basis, partially offset by cost-saving measures.

- *Product Sales.* The increase in service and product expenses as a percentage of revenue for the products segments was primarily due to the mix of products sold for the relative periods, as the 2008 results included several higher margin projects associated with our Southeast Asian operations when compared to the year ended December 31, 2009. Additionally, on a year-over-year basis, a larger proportion of the revenues and related costs for the product sales segment for the year ended December 31, 2009 were provided by our repair and fabrication facility in north Texas at lower margins relative to our Southeast Asian business, including the sale of a large inventory item.

Selling, General and Administrative Expenses

Selling, general and administrative expenses include salaries and other related expenses for our selling, administrative, finance, information technology and human resource functions. Selling, general and administrative expenses decreased $16.8 million, or 8%, for the year ended December 31, 2009 to $181.4 million from $198.2 million during the year ended December 31, 2008. Several cost saving measures were implemented during 2009 including headcount reductions, other payroll concessions and lower outside service costs. These expense reductions were offset by: (1) the loss on the exchange of certain non-monetary assets in Canada during the first quarter of 2009 which totaled $4.9 million; (2) higher bad debt expense, particularly in our drilling services segment and (3) higher losses from the disposal of fixed assets. Excluding the impact of the non-monetary asset exchange in Canada, as a percentage of revenues, selling, general and administrative expense was 17% and 11% for the years ended December 31, 2009 and 2008, respectively.

Depreciation and Amortization

Depreciation and amortization expense increased $19.5 million, or 11%, to $200.7 million for the year ended December 31, 2009 from $181.2 million for the year ended December 31, 2008. The increase in depreciation and amortization expense was the result of the following: (1) depreciation of equipment placed into service throughout 2008, as well as additional equipment purchased in 2009; (2) depreciation and amortization expense related to assets associated with businesses acquired in 2008, some of which did not contribute depreciation expense for the full year ended December 31, 2008 due to the timing of the acquisitions; and (3) an increase in amortization expense associated with intangible assets acquired in business combinations in 2008. As a percentage of revenue, depreciation and amortization expense increased to 19% from 10% for the years ended December 31, 2009 and 2008, respectively. We expected depreciation and amortization expense as a percentage of revenue to remain higher than in recent periods due to the significant investment in capital expenditures made throughout the last three years and the overall decline in activity levels that began in late 2008.

Fixed Asset and Other Intangible Impairment Loss

For the year ended December 31, 2009, we recorded a fixed asset and other intangible impairment loss of $38.6 million. We recorded a charge of $36.2 million related to our contract drilling business in the third quarter of 2009 after determining that the carrying value of certain of these drilling rigs exceeded the undiscounted cash flows associated with these assets and the fair market value estimates for these assets. In the fourth quarter of 2009, we recorded an impairment of intangible assets of $2.5 million related to our completion and production business. We recorded no such impairment charges in 2008.

Goodwill Impairment Loss

We recorded a goodwill impairment loss of $97.6 million for the year ended December 31, 2009 compared to $272.0 million recorded in 2008. These write-downs of goodwill in both 2008 and 2009 were associated with several of our reporting units and were based upon several valuation techniques including a discounted cash flow analysis of expected future earnings associated with these businesses. Our analysis of future cash flows was impacted significantly by the overall decline in oilfield activity in late 2008 which continued throughout 2009.

Interest Expense

Interest expense was $56.9 million and $59.7 million for the years ended December 31, 2009 and 2008, respectively. This 5% decrease in interest expense was attributable primarily to a decrease in the average amount of debt outstanding during the year ended December 31, 2009 and lower interest rates in 2009 compared to 2008 on our outstanding borrowings under revolving credit facilities, which were fully repaid as of June 30, 2009. The weighted-average interest rate of borrowings outstanding at December 31, 2009 and 2008 was approximately 8.0% and 7.0%, respectively.

Taxes

Tax expense (benefit) is comprised of current income taxes and deferred income taxes. The current and deferred taxes added together provide an indication of an effective rate of income tax.

We recorded a tax benefit of $63.1 million for the year ended December 31, 2009 at an effective rate of approximately 25.8% compared to a tax expense of $72.3 million for the year ended December 31, 2008. The lower effective tax rate in 2009 was due to the impairment of goodwill with limited tax basis. Our tax rate for the year ended December 31, 2008 was impacted significantly by a $272.0 million impairment of goodwill which had a limited tax basis, as the majority of the goodwill arose through stock purchase transactions with little or no tax basis. Excluding the impact of the goodwill impairment charges, our effective tax rates for the years ended December 31, 2009 and 2008 would have been 33.9% and 35.5%.

Liquidity and Capital Resources

As of December 31, 2010, we had working capital, net of cash, of $276.8 million and cash and cash equivalents of $126.7 million, compared to working capital, net of cash, of $200.8 million and cash and cash equivalents of $77.4 million at December 31, 2009. This increase in working capital was primarily due to an increase in accounts receivable, partially offset by an increase in accounts payable, associated with favorable operating results, and an increase in accrued expenses due to higher earnings-based incentive compensation accruals. We also received net tax refunds of approximately $31.1 million during 2010.

Our primary liquidity needs are to fund capital expenditures and general working capital. In addition, we have historically obtained capital to fund strategic business acquisitions. Our primary sources of funds have been cash flow from operations, proceeds from borrowings under bank credit facilities and a private placement of debt that was subsequently exchanged for publicly registered debt.

We anticipate that our cash generated from operations and our current cash balance will be sufficient to fund the majority of our cash requirements for the next twelve months, however borrowings under our amended revolving credit facility, future debt offerings and/or future public equity offerings may also be used to fund future acquisitions or to satisfy our other liquidity needs. We believe that funds from these sources will be sufficient to meet both our short-term working capital requirements and our long-term capital requirements. If our plans or assumptions change, or are inaccurate, or if we make further acquisitions, we may have to raise additional capital. Our ability to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, and more broadly, on the availability of equity and debt financing, which will be affected by prevailing economic conditions in our industry, and general financial, business and other factors, some of which are beyond our control. In addition, new debt obtained could include service requirements based on higher interest paid and shorter maturities and could impose a significant burden on our results of operations and financial condition. The issuance of additional equity securities could result in significant dilution to stockholders.

On October 13, 2009, we completed an amendment to our existing revolving credit facilities (the "Third Amendment") which modified the structure of the credit facility to an asset-based facility subject to borrowing base restrictions. This amendment provided us with less restrictive financial debt covenants and reduced borrowing capacity under the facility.

The following table summarizes cash flows by type for the periods indicated (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Cash flows provided by (used in):			
Operating activities	$ 216,158	$ 285,204	$ 350,409
Investing activities	(174,088)	(18,128)	(374,098)
Financing activities	6,817	(207,991)	27,990

Net cash provided by operating activities decreased $69.0 million for the year ended December 31, 2010 compared to the year ended December 31, 2009, and decreased $65.2 million for the year ended December 31, 2009 compared to the year ended December 31, 2008. The decrease in operating cash flows for the year ended December 31, 2010 compared to the year ended December 31, 2009 was primarily due to an increase in trade receivables resulting from a favorable increase in oilfield activity partially offset by an increase in payables and the collection of a large income tax receivable. During 2010, cash receipts activity remained favorable, but with an increase in sales there was an increase in outstanding receivables. The decrease in operating cash flows for 2009 compared to 2008 reflects the overall decline in oilfield activity in late 2008 and throughout 2009.

Net cash used in investing activities increased $156.0 million for the year ended December 31, 2010 compared to the year ended December 31, 2009 and decreased $356.0 million for the year ended December 31, 2009 compared to the year ended December 31, 2008. Of this increase in 2010, $145.0 million was due to an increase in capital expenditures, which was only $37.4 million for the year ended December 31, 2009. We decreased our overall capital expenditures in 2009 in response to the decline in commodity prices and lower activity levels. In addition, we invested $33.7 million in business acquisitions in 2010, with no corresponding business acquisitions in 2009. The decrease in 2009 compared to 2008 was due to investment in capital expenditures of $253.8 million and acquisitions of $180.2 million in 2008.

Net cash provided by financing activities was $6.8 million for the year ended December 31, 2010 compared to $208.0 million of cash used for financing activities for the year ended December 31, 2009, and compared to cash provided by financing activities of $28.0 million for the year ended December 31, 2008. In 2009, we focused on eliminating obligations under our credit facility and building cash. We repaid long-term borrowings under our debt facilities totaling $200.6 million and only borrowed $3.2 million during 2009. The primary source of these funds in 2009 was cash flow from operations. Our long-term debt balances, including current maturities, were $650.0 and $650.2 million as of December 31, 2010 and 2009, respectively.

In 2010, we invested significantly more on capital expenditures and acquisitions than we did during 2009. We will continue to evaluate acquisitions of complementary companies. We believe that our operating cash flows and borrowing capacity will be sufficient to fund our operations and capital expenditures for the next 12 months.

Dividends

We did not pay dividends on our $0.01 par value common stock during the years ended December 31, 2010, 2009 and 2008. We do not intend to pay dividends in the foreseeable future, but rather plan to reinvest such funds in our business. Furthermore, our credit facility contains restrictive debt covenants which preclude us from paying future dividends on our common stock.

Description of Our Indebtedness

Senior Notes.

On December 6, 2006, we issued 8.0% senior notes with a face value of $650.0 million through a private placement of debt. These notes mature in 10 years, on December 15, 2016, and require semi-annual interest payments, paid in arrears and calculated based on an annual rate of 8.0%, on June 15 and December 15, of each year, which commenced on June 15, 2007. There was no discount or premium associated with the issuance of these notes. The senior notes are guaranteed by all of our current domestic subsidiaries. The senior notes have covenants which, among other things: (1) limit the amount of additional indebtedness we can incur; (2) limit restricted payments such as a dividend; (3) limit our ability to incur liens or encumbrances; (4) limit our ability to purchase, transfer or dispose of significant assets; (5) limit our ability to purchase or redeem stock or subordinated debt; (6) limit our ability to enter into transactions with affiliates; (7) limit our ability to merge with or into other companies or transfer all or substantially all of our assets; and (8) limit our ability to enter into sale and leaseback transactions. We have the option to redeem all or part of these notes on or after December 15, 2011. Additionally, we may redeem some or all of the notes prior to December 15, 2011 at a price equal to 100% of the principal amount of the notes plus a make-whole premium.

Pursuant to a registration rights agreement with the holders of our 8.0% senior notes, on June 1, 2007, we filed a registration statement on Form S-4 with the SEC which enabled these holders to exchange their notes for publicly registered notes with substantially identical terms. These holders exchanged 100% of the notes for publicly traded notes on July 25, 2007. On August 28, 2007, we entered into a supplement to the indenture governing the 8.0% senior notes, whereby additional domestic subsidiaries became guarantors under the indenture. Effective April 1, 2009, we entered into a second supplement to this indenture whereby additional domestic subsidiaries became guarantors under the indenture.

Credit Facility.

We maintain a senior secured facility (the "Credit Agreement") with Wells Fargo Bank, National Association, as U.S. Administrative Agent, HSBC Bank Canada, as Canadian Administrative Agent, and certain other financial institutions. On October 13, 2009, we entered into the Third Amendment (the Credit Agreement after giving effect to the Third Amendment, the "Amended Credit Agreement") and modified the structure of our existing credit facility to an asset-based facility subject to borrowing base restrictions. In connection with the Third Amendment, Wells Fargo Capital Finance, LLC (formerly known as Wells Fargo Foothill, LLC) replaced Wells Fargo Bank, National Association, as U.S. Administrative Agent and also serves as U.S. Issuing Lender and U.S. Swingline Lender under the Amended Credit Agreement. The Amended Credit Agreement provides for a U.S. revolving credit facility of up to $225 million that matures in December 2011 and a Canadian revolving credit facility of up to $15 million (with Integrated Production Services Ltd., one of our wholly-owned subsidiaries, as the borrower thereof ("Canadian Borrower")) that matures in December 2011. The Amended Credit Agreement includes a provision for a "commitment increase", as defined therein, which permits us to effect up to two separate increases in the aggregate commitments under the Amended Credit Agreement by designating one or more existing lenders or other banks or financial institutions, subject to the bank's sole discretion as to participation, to provide additional aggregate financing up to $75 million, with each committed increase equal to at least $25 million in the U.S., or $5 million in Canada, and in accordance with other provisions as stipulated in the Amended Credit Agreement. Certain portions of the credit facilities are available to be borrowed in U.S. dollars, Canadian dollars and other currencies approved by the lenders.

Our U.S. borrowing base is limited to: (1) 85% of U.S. eligible billed accounts receivable, less dilution, if any, plus (2) the lesser of 55% of the amount of U.S. eligible unbilled accounts receivable or $10.0 million, plus (3) the lesser of the "equipment reserve amount" and 80% times the most recently determined "net liquidation percentage", as defined in the Amended Credit Agreement, times the value of our and the U.S. subsidiary guarantors' equipment, provided that at no time shall the amount determined under this clause exceed 50% of the U.S. borrowing base, minus (4) the aggregate sum of reserves established by the U.S. Administrative Agent, if any. The "equipment reserve amount" means $50.0 million upon the effective date of the Third Amendment, less $0.6 million for each subsequent month, not to be reduced below zero in the aggregate.

The Canadian borrowing based is limited to: (1) 80% of Canadian eligible billed accounts receivable, plus (2) if the Canadian Borrower has requested credit for equipment under the Canadian borrowing base, the lesser of (a) $15.0 million, and (b) 80% *times* the most recently determined "net liquidation percentage", as defined in the Amended Credit Agreement, times the value (calculated on a basis consistent with our historical accounting practices) of our and the US subsidiary guarantors' equipment, minus (3) the aggregate amount of reserves established by our Canadian Administrative Agent, if any.

Subject to certain limitations set forth in the Amended Credit Agreement, we have the ability to elect how interest under the Amended Credit Agreement will be computed. Interest under the Amended Credit Agreement may be determined by reference to (1) the London Inter-bank Offered Rate, or LIBOR, plus an applicable margin between 3.75% and 4.25% per annum (with the applicable margin depending upon our "excess availability amount", as defined in the Amended Credit Agreement) or (2) the "Base Rate" (which means the higher of the Prime Rate, Federal Funds Rate plus 0.50%, 3-month LIBOR plus 1.00% and 3.50%), plus the applicable margin, as described above. For the period from the effective date of the Third Amendment until the six month anniversary of the effective date of the Third Amendment, interest was computed with an applicable margin rate of 4.00%. If an event of default exists or continues under the Amended Credit Agreement, advances will bear interest as described above with an applicable margin rate of 4.25% plus 2.00%. Additionally, if an event of default exists under the Amended Credit Agreement, as defined therein, the lenders could accelerate the maturity of the obligations outstanding thereunder and exercise other rights and remedies. Interest is payable monthly.

Under the Amended Credit Agreement, we are permitted to prepay our borrowings and we have the right to terminate, in whole or in part, the unused portion of the U.S. commitments in $1.0 million increments upon written notice to the U.S. Administrative Agent. If all of the U.S. facility is terminated, the Canadian facility must also be terminated.

All of the obligations under the U.S. portion of the Amended Credit Agreement are secured by first priority liens on substantially all of our assets and the assets of our U.S. subsidiaries as well as a pledge of approximately 66% of the stock of our first-tier foreign subsidiaries. Additionally, all of the obligations under the U.S. portion of the Amended Credit Agreement are guaranteed by substantially all of our U.S. subsidiaries. The obligations under the Canadian portion of the Amended Credit Agreement are secured by first priority liens on substantially all of our assets and the assets of our subsidiaries (other than our Mexican subsidiary). Additionally, all of the obligations under the Canadian portion of the Amended Credit Agreement are guaranteed by us as well as certain of our subsidiaries.

The Amended Credit Agreement also contains various covenants that limit our and our subsidiaries' ability to: (1) grant certain liens; (2) incur additional indebtedness; (3) make certain loans and investments; (4) make capital expenditures; (5) make distributions; (6) make acquisitions; (7) enter into hedging transactions; (8) merge or consolidate; or (9) engage in certain asset dispositions. The Amended Credit Agreement contains one financial maintenance covenant which requires us and our subsidiaries, on a consolidated basis, to maintain a "fixed charge coverage ratio", as defined in the Amended Credit Agreement, of not less than 1.10 to 1.00. This covenant is only tested if our "excess availability amount", as defined under the Amended Credit Agreement, plus certain qualified cash and cash equivalents (collectively "Liquidity") is less than $50.0 million for a period of 5 consecutive days and continues only until such time as our Liquidity has been greater than or equal to $50.0 million for a period of 90 consecutive days or greater than or equal to $75.0 million for a period of 45 consecutive days.

Our fixed charge coverage ratio covenant is calculated, for fiscal quarters ending after September 30, 2009, as the ratio of "EBITDA" calculated for the four fiscal quarter period ended after September 30, 2009 minus capital expenditures made with cash (to the extent not already incurred in a prior period) or incurred during such four quarter period, compared to "fixed charges", calculated for the four quarters then ended. "EBITDA" is defined in the Amended Credit Agreement as consolidated net income for the period plus, to the extent deducted in determining our consolidated net income, interest expense, taxes, depreciation, amortization and other non-cash charges for such period, provided that EBITDA shall be subject to pro forma adjustments for acquisitions and non-ordinary course asset sales assuming that such transactions occurred on the first day of the determination period, which adjustments shall be made in accordance with the guidelines for pro forma presentations set forth by the Securities and Exchange Commission. "Fixed charges", as defined in the Amended Credit Agreement, include interest expense, among other things, reduced by the amortization of transaction fees associated with the Third Amendment.

We were not subject to the fixed charge coverage ratio covenant in the Amended Credit Agreement as of December 31, 2010 since the Excess Availability Amount plus Qualified Cash Amount (each as defined in the Amended Credit Agreement) exceeded $50 million. If we were subject to the fixed charge coverage ratio covenant, we would have been in compliance as of December 31, 2010.

There were no revolving borrowings outstanding under our U.S. or Canadian revolving credit facilities as of December 31, 2010. The weighted average interest rate for our revolving credit facilities during the twelve months ended December 31, 2010 was 8.0%. There were letters of credit outstanding under the U.S. revolving portion of the facility totaling $26.4 million, which reduced the available borrowing capacity as of December 31, 2010. We incurred fees related to our letters of credit as of December 31, 2010 at 3.75% per annum. For the twelve months ended December 31, 2010, fees related to our letters of credit were calculated using a 360-day provision, at 4.0% per annum. The net excess availability under our borrowing base calculations for the U.S. and Canadian revolving facilities at December 31, 2010 was $187.4 million and $8.4 million, respectively.

Outstanding Debt and Operating Lease Commitments

The following table summarizes our known contractual obligations as of December 31, 2010 (in thousands):

	Payments Due by Period				
Contractual Obligations	**Total**	**2011**	**2012-2013**	**2014-2015**	**Thereafter**
Long-term debt, including capital (finance) lease obligations	$ 650,000	$ —	$ —	$ —	$650,000
Interest on 8% senior notes issued December 6, 2006	307,667	52,000	104,000	104,000	47,667
Purchase obligations(1)	45,376	45,376	—	—	—
Operating lease obligations	92,945	27,287	39,162	15,441	11,055
Total contractual obligations	$1,095,988	$124,663	$143,162	$119,441	$708,722

(1) Purchase obligations were pursuant to non-cancelable equipment purchase orders outstanding as of December 31, 2010. We have no significant purchase orders which extend beyond one year.

We have entered into agreements to purchase certain equipment for use in our business, which are included as purchase obligations in the table above to the extent that these obligations represent firm non-cancelable commitments. The manufacture of this equipment requires lead-time and we generally are committed to accept this equipment at the time of delivery, unless arrangements have been made to cancel delivery in accordance with the purchase agreement terms. We spent $169.9 million for equipment purchases and other capital expenditures during the year ended December 31, 2010.

We expect to continue to acquire complementary companies and evaluate potential acquisition targets. We may use cash from operations, proceeds from future debt or equity offerings and borrowings under our amended revolving credit facility for this purpose.

Off-Balance Sheet Arrangements

We have entered into operating lease arrangements for our light vehicle fleet, certain of our specialized equipment and for our office and field operating locations in the normal course of business. The terms of the facility leases range from monthly to five years. The terms of the light vehicle leases range from three to four years. The terms of the specialized equipment leases range from two to six years. Annual payments pursuant to these leases are included above in the table under "— Outstanding Debt and Operating Lease Commitments."

Recent Accounting Pronouncements and Authoritative Literature

The FASB has addressed the issue of business combinations during recent years. In December 2007, the FASB issued guidance regarding business combinations that substantially replaced previously existing guidance, while maintaining the precepts prescribed therein, and further requiring that all assets and liabilities and non-controlling interests of an acquired business be measured at their fair value, with limited exceptions, including the recognition of acquisition-related costs and anticipated restructuring costs separate from the acquired net assets. In addition, entities must recognize pre-acquisition contingencies, as well as assets and liabilities assumed arising from contractual contingencies as of the acquisition date, measured at acquisition-date fair values, and must recognize all other contractual contingencies as of the acquisition date, measured at their acquisition-date fair values only if it is more likely than not that these contingencies meet the definition of an asset or liability. In addition, this standard provides guidance for measuring goodwill and recording a bargain purchase, defined as a business combination in which total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any non-controlling interest in the acquiree, and states that the acquiring entity must recognize that excess in earnings as a gain attributable to the acquirer. The FASB amended this guidance in April 2009 as it relates to accounting for assets and liabilities assumed in a business combination which arise from contingencies. This amendment requires that contingent assets acquired and liabilities assumed in a business combination to be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the measurement period. If fair value cannot be reasonably estimated during the measurement period, the contingent asset or liability would be recognized as a contingency, in accordance with existing U.S. GAAP, with reasonable estimation of the amount of loss, if any. This amendment also eliminated the specific subsequent accounting guidance for contingent assets and liabilities, without significantly revising the original guidance. However, contingent consideration arrangements of an acquiree assumed by the acquirer in a business combination would still be initially and subsequently measured at fair value. We originally adopted the revised guidance for business combinations when it became effective on January 1, 2009, and the amendment thereto, subsequently in 2009. In December 2010, the FASB updated this guidance to require each public entity that presents comparative financial statements to disclose the revenue and earnings of the combined entity as if the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. In addition, this amendment expands the supplemental pro forma disclosures related to such a business combination to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. This most recent amendment should be accounted for prospectively for business combinations for which the acquisition date is on or after January 1, 2011, for calendar-year reporting entities. Early adoption is permitted. Although we did not early adopt this standard, we do not expect this guidance to have a material impact on our financial position, results of operations or cash flows. We will comply with this update for business combinations that have a material impact on our financial results.

In May 2009, the FASB issued a standard regarding subsequent events that provides guidance as to when an entity should recognize events or transactions occurring after a balance sheet date in its financial statements and the necessary disclosures related to these events. Specifically, the entity should recognize subsequent events that provide evidence about conditions that existed at the balance sheet date, including significant estimates used to prepare financial statements. Originally, this standard required entities to disclose the date through which subsequent events had been evaluated and whether that date was the date the financial statements were issued or the date the financial statements were available to be issued. We adopted this accounting standard effective June 30, 2009 and applied its provisions prospectively. In February 2010, the FASB modified this standard to eliminate the requirement for publicly-traded entities to disclose the date through which subsequent events have been evaluated.

In January 2010, the FASB issued "Fair Value Measurements and Disclosure (Topic 820)" which clarified the disclosure requirements of existing U.S. GAAP related to fair value measurements. This standard requires additional disclosures about recurring and non-recurring fair value measurements as follows: (1) for transfers in and out of Level 1 and Level 2 fair value measurements, as those terms are currently defined in existing authoritative literature, a reporting entity is required to disclose the amount of the movement between levels and an explanation for the movement; (2) for activity at Level 3, primarily fair value measurements based on unobservable inputs, a reporting entity is required to present separately information about purchases, sales, issuances and settlements, as opposed to presenting such transactions on a net basis; (3) in the event of a disaggregation, a reporting entity is required to provide fair value measurement disclosure for each class of assets and liabilities; and (4) a reporting entity is required to provide disclosures about the valuation techniques and inputs used to measure fair value for both recurring and non-recurring fair value measurements for items that fall in either Level 2 or Level 3. These disclosure requirements are effective for interim and annual reporting periods beginning after December 15, 2009, except for disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements for which disclosure becomes effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years.

On March 30, 2010, the President of the United States signed the Health Care and Education Reconciliation Act of 2010, which is a reconciliation bill that amends the Patient Protection and Affordable Care Act that was signed by the President on March 23, 2010. Certain provisions of this law became effective during 2010. We have reviewed our health insurance plan provisions with third-party consultants and continue to evaluate our position relative to the changes in the law. We do not believe that the provisions which have taken effect will have a significant impact on the operation of our existing health insurance plan. However, future provisions under the law which become effective in subsequent periods may impact our health insurance plan and our overall financial position. We are evaluating these provisions as they become effective and continue to seek guidance from the FASB and SEC related to the implications of this new legislation on accounting and disclosure requirements. We expect that this legislation will have an impact on our financial position, results of operations and cash flows, but we cannot determine the extent of the impact at this time.

In December 2010, the FASB issued additional guidance related to accounting for intangible assets and goodwill. The amendments in this update modify Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist. The qualitative factors are consistent with the existing guidance and examples, which require that goodwill of a reporting unit be tested for impairment between annual test dates if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. This update is effective for public entities with fiscal years beginning after December 15, 2010 and interim periods within those years. Early adoption is not permitted. We are currently evaluating the effect this proposed guidance may have on our financial position, results of operations and cash flows.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

The demand, pricing and terms for oil and gas services provided by us are largely dependent upon the level of activity for the U.S. and Canadian gas industry. Industry conditions are influenced by numerous factors over which we have no control, including, but not limited to: the supply of and demand for oil and gas; the level of prices, and expectations about future prices, of oil and gas; the cost of exploring for, developing, producing and delivering oil and gas; the expected rates of declining current production; the discovery rates of new oil and gas reserves; available pipeline and other transportation capacity; weather conditions; domestic and worldwide economic conditions; political instability in oil-producing countries; technical advances affecting energy consumption; the price and availability of alternative fuels; the ability of oil and gas producers to raise equity capital and debt financing; and merger and divestiture activity among oil and gas producers.

The level of activity in the U.S. and Canadian oil and gas exploration and production industry is volatile. No assurance can be given that our expectations of trends in oil and gas production activities will reflect actual future activity levels or that demand for our services will be consistent with the general activity level of the industry. Any prolonged substantial reduction in oil and gas prices would likely affect oil and gas exploration and development efforts and therefore affect demand for our services. A material decline in oil and gas prices or U.S. and Canadian activity levels could have a material adverse effect on our business, financial condition, results of operations and cash flows.

For the years ended December 31, 2010 and 2009, approximately 5% of our revenues from continuing operations and 4% of our total assets were denominated in Canadian dollars, our functional currency in Canada. As a result, a material decrease in the value of the Canadian dollar relative to the U.S. dollar may negatively impact our revenues, cash flows and net income. Each one percentage point change in the value of the Canadian dollar would have impacted our revenues for the year ended December 31, 2010 by approximately $0.8 million, or $0.5 million net of tax. We do not currently use hedges or forward contracts to offset this risk.

Our Mexican operation uses the U.S. dollar as its functional currency, and as a result, all transactions and translation gains and losses are recorded currently in the financial statements. The balance sheet amounts are translated into U.S. dollars at the exchange rate at the end of the month and the income statement amounts are translated at the average exchange rate for the month. We estimate that a hypothetical one percentage point change in the value of the Mexican peso relative to the U.S. dollar would have impacted our revenues for the year ended December 31, 2010 by approximately $0.5 million, or $0.3 million, net of tax. Currently, we conduct a portion of our business in Mexico in the local currency, the Mexican peso.

Item 8. ***Financial Statements and Supplementary Data.***

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Complete Production Services, Inc.

We have audited the accompanying consolidated balance sheets of Complete Production Services, Inc. as of December 31, 2010 and 2009, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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 Complete Production Services, Inc. as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Complete Production Services, Inc.'s internal control over financial reporting as of December 31, 2010, 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 18, 2011, expressed an unqualified opinion that Complete Production Services, Inc. maintained, in all material respects, effective internal control over financial reporting.

/s/ Grant Thornton LLP

Houston, Texas
February 18, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Complete Production Services, Inc.

We have audited Complete Production Services, Inc.'s internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Complete Production Services, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Complete Production Services, Inc.'s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and 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, Complete Production Services, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Complete Production Services, Inc. as of December 31, 2010 and 2009, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010, and our report dated February 18, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ **Grant Thornton LLP**

Houston, Texas
February 18, 2011

COMPLETE PRODUCTION SERVICES, INC.

Consolidated Balance Sheets
December 31, 2010 and 2009

	2010	2009
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 126,681	$ 77,360
Accounts receivable, net of allowance for doubtful accounts of $4,160 and $12,564, respectively	345,648	171,284
Inventory, net of obsolescence reserve of $2,453 and $888, respectively	33,536	37,464
Prepaid expenses	18,700	17,943
Income tax receivable	23,462	57,606
Current deferred tax assets	2,499	8,158
Other current assets	1,384	111
Total current assets	551,910	369,926
Property, plant and equipment, net	956,028	941,133
Intangible assets, net of accumulated amortization of $21,293 and $15,476, respectively	9,209	13,243
Deferred financing costs, net of accumulated amortization of $9,316 and $6,266, respectively	9,694	12,744
Goodwill	250,533	243,823
Restricted cash	17,000	—
Other long-term assets	6,202	7,985
Total assets	$1,800,576	$1,588,854
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ —	$ 228
Accounts payable	75,099	31,745
Accrued liabilities	44,291	41,102
Accrued payroll and payroll burdens	26,568	13,559
Accrued interest	2,446	3,206
Notes payable	—	1,069
Income taxes payable	—	813
Total current liabilities	148,404	91,722
Long-term debt	650,000	650,002
Deferred income taxes	190,422	148,240
Other long-term liabilities	5,916	—
Total liabilities	994,742	889,964
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value per share, 200,000,000 shares authorized, 76,443,926 (2009 — 75,278,406) issued	764	752
Preferred stock, $0.01 par value per share, 5,000,000 shares authorized, no shares issued and outstanding	—	—
Additional paid-in capital	657,993	636,904
Retained earnings	126,165	42,007
Treasury stock, 167,643 (2009 — 54,313) shares at cost	(1,765)	(334)
Accumulated other comprehensive income	22,677	19,561
Total stockholders' equity	805,834	698,890
Total liabilities and stockholders' equity	$1,800,576	$1,588,854

See accompanying notes to consolidated financial statements.

COMPLETE PRODUCTION SERVICES, INC.

Consolidated Statements of Operations
Years Ended December 31, 2010, 2009 and 2008

	Year Ended December 31,		
	2010	2009	2008
	(In thousands, except per share data)		
Revenue:			
Service	$1,527,618	$1,012,313	$1,775,813
Product	33,775	44,081	59,102
	1,561,393	1,056,394	1,834,915
Service expenses	985,093	692,164	1,094,574
Product expenses	25,947	33,201	41,914
Selling, general and administrative expenses	175,445	181,420	198,200
Depreciation and amortization	181,823	200,732	181,197
Fixed asset and other intangibles impairment loss	—	38,646	—
Goodwill impairment loss	—	97,643	272,006
Income (loss) from continuing operations before interest and taxes	193,085	(187,412)	47,024
Interest expense	57,669	56,895	59,729
Interest income	(322)	(79)	(301)
Write-off of deferred financing costs	—	528	—
Income (loss) from continuing operations before taxes	135,738	(244,756)	(12,404)
Taxes	51,580	(63,088)	72,305
Income (loss) from continuing operations	84,158	(181,668)	(84,709)
Loss from discontinued operations (net of tax expense of $0, $0, and $3,865, respectively)	—	—	(4,859)
Net income (loss)	$ 84,158	$ (181,668)	$ (89,568)
Earnings (loss) per share information:			
Continuing operations	$ 1.11	$ (2.42)	$ (1.15)
Discontinued operations	—	—	(0.07)
Basic earnings (loss) per share	$ 1.11	$ (2.42)	$ (1.22)
Continuing operations	$ 1.08	$ (2.42)	$ (1.15)
Discontinued operations	—	—	(0.07)
Diluted earnings (loss) per share	$ 1.08	$ (2.42)	$ (1.22)
Weighted average shares:			
Basic	76,048	75,095	73,600
Diluted	77,684	75,095	73,600

See accompanying notes to consolidated financial statements.

COMPLETE PRODUCTION SERVICES, INC.

Consolidated Statements of Comprehensive Income (Loss)
Years Ended December 31, 2010, 2009 and 2008

	Year Ended December 31,		
	2010	2009	2008
		(In thousands)	
Net income (loss)	$84,158	$(181,668)	$ (89,568)
Change in cumulative translation adjustment	3,116	7,059	(18,359)
Comprehensive income (loss)	$87,274	$(174,609)	$(107,927)

See accompanying notes to consolidated financial statements.

COMPLETE PRODUCTION SERVICES, INC.

Consolidated Statement of Stockholders' Equity
Years Ended December 31, 2010, 2009 and 2008

	Number of Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income	Total
			(In thousands, except share data)				
Balance at December 31, 2007	72,509,511	$725	$581,404	$ 313,243	$ (202)	$ 30,861	$ 926,031
Net loss	—	—	—	(89,568)	—	—	(89,568)
Change in cumulative translation adjustment	—	—	—	—	—	(18,359)	(18,359)
Issuance of common stock:							
Acquisition of AWS	588,292	6	8,848	—	—	—	8,854
Acquisition — Double Jack shares	7,234	—	225	—	—	—	225
Exercise of stock options	1,238,819	13	12,001	—	—	—	12,014
Expense related to employee stock options	—	—	5,436	—	—	—	5,436
Excess tax benefit from share-based compensation	—	—	9,144	—	—	—	9,144
Vested restricted stock	422,461	4	(4)	—	—	—	—
Amortization of non-vested restricted stock	—	—	6,934	—	—	—	6,934
Balance at December 31, 2008	74,766,317	$748	$623,988	$ 223,675	$ (202)	$ 12,502	$ 860,711
Net loss	—	—	—	(181,668)	—	—	(181,668)
Change in cumulative translation adjustment	—	—	—	—	—	7,059	7,059
Exercise of stock options	123,858		496	—	—	—	496
Expense related to employee stock options	—	—	3,987	—	—	—	3,987
Excess tax benefit from share-based compensation	—	—	215	—	—	—	215
Purchase of treasury shares	(18,743)	—	—	—	(132)	—	(132)
Vested restricted stock	406,974	4	(4)	—	—	—	—
Amortization of non-vested restricted stock	—	—	8,222	—	—	—	8,222
Balance at December 31, 2009	75,278,406	$752	$636,904	$ 42,007	$ (334)	$ 19,561	$ 698,890
Net income	—	—	—	84,158	—	—	84,158
Change in cumulative translation adjustment	—	—	—	—	—	3,116	3,116
Exercise of stock options	599,035	6	8,076	—	—	—	8,082
Expense related to employee stock options	—	—	2,321	—	—	—	2,321
Excess tax benefit from share-based compensation	—	—	1,465	—	—	—	1,465
Purchase of treasury shares	(113,330)	(1)	1	—	(1,431)	—	(1,431)
Vested restricted stock	679,815	7	(7)	—	—	—	—
Amortization of non-vested restricted stock	—	—	9,233	—	—	—	9,233
Balance at December 31, 2010	76,443,926	$764	$657,993	$ 126,165	$(1,765)	$ 22,677	$ 805,834

See accompanying notes to consolidated financial statements.

COMPLETE PRODUCTION SERVICES, INC.

Consolidated Statements of Cash Flows
Years Ended December 31, 2010, 2009 and 2008

	Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Cash provided by:			
Net income (loss)	$ 84,158	$(181,668)	$ (89,568)
Items not affecting cash:			
Depreciation and amortization	181,823	200,732	183,191
Deferred income taxes	47,841	(7,567)	20,827
Fixed asset and other intangibles impairment loss	—	38,646	—
Goodwill impairment loss	—	97,643	272,006
Write-off of deferred financing fees	—	528	—
Loss on sale of discontinued operations	—	—	6,935
Excess tax benefit from share-based compensation	(1,465)	(215)	(9,144)
Non-cash compensation expense	11,554	12,209	12,370
(Gain) loss on non-monetary asset exchange	(493)	4,868	—
Provision for (recoveries of) bad debt expense	(159)	10,770	4,344
Loss on retirement of fixed assets	839	10,284	3,778
Provision for write-off of note receivable	1,926	—	—
Other	2,995	2,081	1,956
Changes in operating assets and liabilities, net of effect of acquisitions:			
Accounts receivable	(173,328)	155,303	(18,873)
Inventory	3,585	4,339	(8,653)
Prepaid expenses and other current assets	(1,095)	11,292	8,118
Accounts payable	25,831	(24,544)	(10,199)
Income taxes	34,093	(30,892)	(13,873)
Restricted cash	(17,000)	—	—
Accrued liabilities and other	15,053	(18,605)	(12,806)
Net cash provided by operating activities	216,158	285,204	350,409
Investing activities:			
Business acquisitions, net of cash acquired	(33,721)	—	(180,154)
Additions to property, plant and equipment	(145,023)	(37,431)	(253,776)
Proceeds from sale of fixed assets	5,482	20,800	7,666
Proceeds from sale of disposal group	—	—	50,150
Other	(826)	(1,497)	2,016
Net cash used in investing activities	(174,088)	(18,128)	(374,098)
Financing activities:			
Issuances of long-term debt	—	3,194	350,115
Repayments of long-term debt	(230)	(200,609)	(329,282)
Repayments of notes payable	(1,069)	(8,244)	(14,001)
Proceeds from issuances of common stock	8,082	496	12,014
Deferred financing fees	—	(2,911)	—
Treasury stock purchased	(1,431)	(132)	—
Excess tax benefit from share-based compensation	1,465	215	9,144
Net cash (used in) provided by financing activities	6,817	(207,991)	27,990
Effect of exchange rate changes on cash	434	(225)	1,165
Change in cash and cash equivalents	49,321	58,860	5,466
Cash and cash equivalents, beginning of period	77,360	18,500	13,034
Cash and cash equivalents, end of period	$ 126,681	$ 77,360	$ 18,500
Supplemental cash flow information:			
Cash paid for interest, net of capitalized interest	$ 54,301	$ 52,686	$ 58,812
Cash paid (refund received) for taxes	$ (31,067)	$ (25,414)	$ 71,365
Significant non-cash investing and financing activities:			
Non-cash capital expenditures	$ 25,952	$ 1,056	$ —
Note issued to finance insurance premiums	$ —	$ 7,960	$ —
Common stock issued for acquisitions	$ —	$ —	$ 9,079
Assets received as proceeds from sale of disposal group	$ —	$ —	$ 7,987
Debt acquired in acquisition	$ —	$ —	$ 429

See accompanying notes to consolidated financial statements.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements
(In thousands, except share and per share data)

1. General:

(a) Nature of operations:

Complete Production Services, Inc. is a provider of specialized services and products focused on developing hydrocarbon reserves, reducing operating costs and enhancing production for oil and gas companies. Complete Production Services, Inc. focuses its operations on basins within North America and manages its operations from regional field service facilities located throughout the U.S. Rocky Mountain region, Texas, Oklahoma, Louisiana, Arkansas, Pennsylvania, western Canada, Mexico and Southeast Asia.

References to "Complete", the "Company", "we", "our" and similar phrases are used throughout these financial statements and relate collectively to Complete Production Services, Inc. and its consolidated affiliates.

On April 20, 2006, we entered into an underwriting agreement in connection with our initial public offering and became subject to the reporting requirements of the Securities Exchange Act of 1934. On April 21, 2006, our common stock began trading on the New York Stock Exchange under the symbol "CPX". On April 26, 2006, we completed our initial public offering. See Note 12, "Stockholders' equity".

(b) Basis of presentation:

Our consolidated financial statements are expressed in U.S. dollars and have been prepared by us in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"). In preparing financial statements, we make informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, we review our estimates, including those related to impairment of long-lived assets and goodwill, contingencies and income taxes. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

These audited consolidated financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary for a fair statement of the financial position of Complete as of December 31, 2010 and 2009 and the statements of operations, the statements of comprehensive income (loss), the statements of stockholders' equity and the statements of cash flows for each of the three years in the period ended December 31, 2010. We believe that these financial statements contain all adjustments necessary so that they are not misleading. Certain reclassifications have been made in order to present results on a comparable basis with amounts for 2009.

In May 2008, our Board of Directors authorized and committed to a plan to sell certain operations in the Barnett Shale region of north Texas, consisting primarily of our supply store business, as well as certain non-strategic drilling logistics assets and other completion and production services assets. On May 19, 2008, we sold these operations to a company owned by a former officer of one of our subsidiaries, for which we received proceeds of $50,150 and assets with a fair market value of $7,987. Accordingly, we have revised our financial statements for the year ended December 31, 2008 to classify the related results of operations of this disposal group as discontinued operations. See Note 14, "Discontinued operations".

2. Significant accounting policies:

(a) Basis of preparation:

Our consolidated financial statements include the accounts of the legal entities discussed above and their wholly owned subsidiaries. All material inter-company balances and transactions have been eliminated in consolidation.

(b) Foreign currency translation:

Assets and liabilities of foreign subsidiaries, whose functional currencies are the local currency, are translated from their respective functional currencies to U.S. dollars at the balance sheet date exchange rates. Income and expense items are translated at the average rates of exchange prevailing during the period. Foreign exchange gains and losses resulting from translation of account balances are included in income or loss in the year in which they occur. The adjustment resulting from translating the financial statements of such foreign subsidiaries into U.S. dollars is reflected as a separate component of stockholders' equity.

(c) Revenue recognition:

We recognize service revenue when it is realized and earned. We consider revenue to be realized and earned when the services have been provided to the customer, the product has been delivered, the sales price is fixed or determinable and collectibility is reasonably assured. Generally, services are provided over a relatively short time.

Revenue and costs on drilling contracts are recognized as work progresses. Progress is measured and revenues recognized based upon agreed day-rate charges. For certain contracts, we may receive additional lump-sum payments for the mobilization of rigs and other drilling equipment. Consistent with the drilling contract day-rate revenues and charges, revenues and related direct costs incurred for the mobilization are deferred and recognized over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred.

We recognize revenue under service contracts as services are performed. We had no significant unearned revenues associated with long-term service contracts as of December 31, 2010 and 2009.

(d) Cash and cash equivalents:

Short-term investments with maturities of less than three months are considered to be cash equivalents and are recorded at cost, which approximates fair market value. For purposes of the consolidated statements of cash flows, we consider all investments in highly liquid debt instruments with original maturities of three months or less to be cash equivalents. We invest excess cash in overnight investments which are accounted for as cash. At December 31, 2010, our cash and cash equivalents exceeded what is federally insured.

(e) Trade accounts receivable:

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts is our best estimate of the amount of probable credit losses incurred in our existing accounts receivable. We determine the allowance based on historical write-off experience, account aging and our assumptions about the oil and gas industry economic cycle. We review our allowance for doubtful accounts monthly. Past due balances over 90 days and over a specified amount are reviewed individually for collectibility. All other balances are reviewed on a pooled basis. Account balances are charged off against the allowance after all appropriate means of collection have been exhausted and the potential for recovery is considered remote. Considering our customer base, we do not believe that we have any significant concentrations of credit risk other than our concentration in the oil and gas industry. We have no significant off balance-sheet credit exposure related to our customers.

(f) Inventory:

Inventory, which consists of finished goods, materials and supplies held for resale, work in process and bulk fuel, is carried at the lower of cost or market. Market is defined as net realizable value for finished goods and as replacement cost for manufacturing parts and materials. Cost is determined on a first-in, first-out basis for refurbished parts and an average cost basis for all other inventories and includes the cost of raw materials and labor for finished goods. We record a reserve for excess and obsolete inventory based upon specific identification of items based on periodic reviews of inventory on hand.

(g) Property, plant and equipment:

Property, plant and equipment are carried at cost less accumulated depreciation. Major betterments are capitalized. Repairs and maintenance that do not extend the useful life of equipment are expensed.

Depreciation is provided over the estimated useful life of each asset as follows:

Asset	Basis	Rate
Buildings	straight-line	39 years
Field Equipment:		
Wireline, optimization and coiled tubing equipment	straight-line	10 years
Production testing equipment	straight-line	15 years
Drilling rigs	straight-line	20 years
Well-servicing rigs	straight-line	10 to 25 years
Pressure pumping equipment	straight-line	10 years
Office furniture and computers	straight-line	3 to 7 years
Leasehold improvements	straight-line	Shorter of 5 years or the life of the lease
Vehicles and other equipment	straight-line	3 to 10 years

(h) Intangible assets:

Intangible assets, consisting of acquired customer relationships, service marks, non-compete agreements, acquired patents and technology, are carried at cost less accumulated amortization, which is calculated on a straight-line basis over a period of 2 to 10 years depending on the asset's estimated useful life. The weighted average amortization period for these intangible assets was approximately 4 years as of December 31, 2010.

(i) Impairment of long-lived assets:

We review long-lived assets including property, plant and equipment and intangible assets with definite lives for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset. When assets are determined to be held for sale, they are separately presented in the appropriate asset and liability sections of the balance sheet and reported at the lower of the carrying amount or fair value less cost to sell, and are no longer depreciated. We recorded a fixed asset and other intangibles impairment loss of $38,646 for the year ended December 31, 2009. See Note 6, "Property, plant and equipment."

(j) Asset retirement obligations:

Asset retirement obligations are recorded at fair value as a liability in the period in which a legal obligation is incurred associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets in accordance with U.S. GAAP. Furthermore, a corresponding asset is recorded and depreciated over the contractual term of the underlying asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. We recorded asset retirement obligations of $5,022 as of December 31, 2010 related to the expected cost to plug our saltwater disposal wells at the end of the service lives of the assets, as well as other retirement commitments. We did not have significant retirement obligations recorded at December 31, 2009 and 2008.

(k) Deferred financing costs:

Deferred financing costs associated with long-term debt under our revolving credit facilities and senior notes are carried at cost and are expensed over the term of the applicable long-term debt facility or the term of the notes.

(l) Goodwill:

Goodwill represents the excess of costs over the fair value of the assets and liabilities of businesses acquired. U.S. GAAP requires an impairment test at least annually, or more frequently if indicators of impairment are present, whereby we estimate the fair value of the asset by discounting future cash flows at a projected cost of capital rate. If the fair value estimate is less than the carrying value of the asset, an additional test is required whereby we apply a purchase price allocation consistent with authoritative guidance pertaining to business combinations. If impairment is still indicated, we would record an impairment loss in the current reporting period for the amount by which the carrying value of the intangible asset exceeds its implied fair value. We did not record a goodwill impairment for the year ended 2010. We recorded goodwill impairment losses for each of the years ended December 31, 2009 and 2008. See (t) "Fair value measurements" and Note 15, "Segment information."

(m) Deferred income taxes:

We follow the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are determined based upon temporary differences between the carrying amount and tax basis of our assets and liabilities and measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on deferred tax assets and liabilities of a change in the tax rates is recognized in income in the period in which the change occurs. We record a valuation allowance when we believe that it is more likely than not that a deferred tax asset will not be realized.

In assessing the realizability of deferred income tax assets, management considers whether it is more likely than not that some portion or all of the deferred income tax assets will not be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

(n) Financial instruments:

The financial instruments recognized in the balance sheet consist of cash and cash equivalents, trade accounts receivable, revolving credit facilities, accounts payable and accrued liabilities, long-term debt and senior notes. The fair value of our financial instruments approximate their carrying amounts due to their current maturities or market rates of interest, except the senior notes which were issued in December 2006 with a fixed 8% coupon rate. At December 31, 2010 and 2009, the fair value of these notes was $669,500 and $641,875, respectively, based on the published closing prices for the applicable day.

(o) Per share amounts:

In accordance with U.S. GAAP, we use the treasury stock method to calculate the dilutive effect of stock options and non-vested restricted stock on our earnings per share calculations. This method requires that we compare the presumed proceeds from the exercise of options and other dilutive instruments, including the expected tax benefit to us, to the exercise price of the instrument, and assume that we used the net proceeds to purchase shares of our common stock at the average price during the period. These assumed shares are then included in the calculation of the diluted weighted average shares outstanding for the period, if such instruments are not deemed to be anti-dilutive.

(p) Stock-based compensation:

We have stock-based compensation plans for our employees, officers and directors to acquire common stock. For stock option grants made prior to January 1, 2006, no compensation expense was recorded if the stock options were issued at fair value on the date of grant. Accordingly, we did not recognize compensation expense associated with these stock option grants. Subsequent to January 1, 2006, we measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award, with limited exceptions, by using an option pricing model to determine fair value. We applied the modified-prospective transition method to account for grants of stock options between September 30, 2005, the date of our initial filing with the Securities and Exchange Commission, and December 31, 2005. For stock options granted on or after January 1, 2006, we use the prospective transition method to account for these grants and record compensation expense. See Note 12, "Stockholders' equity".

(q) Research and development:

Research and development costs are charged to income as period costs when incurred.

(r) Contingencies:

Liabilities for loss contingencies, including environmental remediation costs not within the scope of FASB guidance provided with regard to asset retirement obligations and which arise from claims, assessments, litigation, fines, and penalties and other sources, are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated.

(s) Measurement uncertainty:

Our consolidated financial statements are prepared in accordance with U.S. GAAP. The preparation of the consolidated financial statements in accordance with U.S. GAAP necessarily requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. We evaluate our estimates including those related to bad debts, inventory obsolescence, useful lives of property, plant and equipment, goodwill, intangible assets, income taxes, contingencies and litigation on an ongoing basis. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances. Under different assumptions or conditions, the actual results could differ, possibly materially, from those previously estimated. Many of the conditions impacting these assumptions are estimates outside of our control.

(t) Fair value measurement:

We evaluate fair value measurements in accordance with U.S. GAAP, which requires us to base our estimates on assumptions that a market participant might use to price an asset or liability, and to establish a hierarchy that prioritizes the information used to determine fair value, whereby quoted market prices in active markets are given highest priority with lowest priority given to data provided by the reporting entity based on unobservable facts. U.S. GAAP requires disclosure of significant fair value measurements by level within the prescribed hierarchy.

We generally apply fair value valuation techniques on a non-recurring basis associated with: (1) valuing assets and liabilities acquired in connection with business combinations and other transactions; (2) valuing potential impairment loss related to long-lived assets; and (3) valuing potential impairment loss related to goodwill and indefinite-lived intangible assets. We generally do not hold a significant investment in trading securities, and we were not party to significant derivative contract arrangements during the years ended December 31, 2010, 2009 or 2008.

Business combinations and other transactions:

We acquired several businesses during the years ended December 31, 2010 and 2008, but did not complete any such business combinations during the year ended December 31, 2009. To determine the fair value of the assets acquired, primarily fixed assets, we generally obtain assistance from an independent appraiser to determine the fair value of the assets acquired based upon the value of comparable assets in the market as of the date of the acquisition. For one business acquired in late 2010, the assets were recently constructed and cost was deemed to approximate fair value at the date of acquisition. In addition, we applied an income method approach to value identifiable intangible assets associated with our acquisitions, as applicable, including customer relationships, trade names and non-compete agreements. For working capital items, including receivables, payables and inventory, carrying value was deemed to approximate fair value. During the year ended December 31, 2010, we recorded an insignificant non-monetary exchange of assets which resulted in a gain on the transaction of $493. The fair value of the assets received in the exchange was $914 and was more readily determinable based upon the seller's price for such equipment received in the exchange. For the year ended December 31, 2009, we acquired certain property, plant and equipment at a subsidiary in Canada through a non-monetary exchange of assets, as further described in Note 6, "Property, plant and equipment." We determined that this transaction had economic substance and that the assets received should be recorded at the fair value of the assets surrendered in the exchange. To determine the fair value of these assets, management obtained assistance from a third-party appraiser and used the orderly-liquidation value of the assets surrendered as an estimate of fair value. This transaction resulted in a loss of $4,868 for the year ended December 31, 2009.

Long-lived assets:

We reviewed our tangible fixed assets and intangible assets with definite lives at December 31, 2010 and noted no significant indicators of impairment. Therefore, no impairment losses related to long-lived assets were recorded for the year ended December 31, 2010. In September 2009, we evaluated the fair value of assets in our contract drilling business with the assistance of a third-party appraiser and determined that the carrying value of certain of these drilling rigs exceeded the fair value estimates. We projected the undiscounted cash flows associated with these rigs, including an estimate of salvage value, and compared these expected future cash flows to the carrying amount of the rigs. If the undiscounted cash flows exceeded the carrying amount, no further testing was performed and the rig was deemed to not be impaired. If the undiscounted cash flows did not exceed the carrying value, we estimated the fair market value of the equipment based on management estimates and general market data obtained by the third-party appraiser using the sales comparison market approach, which included the analysis of recent sales and offering prices of similar equipment to arrive at an indication of the most probable selling price for the equipment. The result of this analysis was a calculated fixed asset impairment of $36,158, which was recorded as an impairment loss in the accompanying statement of operations for the year ended December 31, 2009. This impairment charge was allocated entirely to the Drilling Services business segment. This impairment was deemed necessary due to an overall decline in oil and gas exploration and production activity in late 2008 which extended throughout 2009, as well as management's expectation of future operating results for this business segment for the foreseeable future. We continue to evaluate the remaining useful lives of our drilling rigs, and have considered our depreciation methodology and these estimates of useful lives in our projected future cash flows associated with these assets.

In addition, we evaluated certain long-term intangible assets with definite lives in accordance with U.S. GAAP as of December 31, 2009. Based on our review, we believe that impairment was indicated at one of our businesses due to lower-than-expected results, revised expected future cash flows for the business and changes in local management. Therefore, with the assistance of a third-party appraiser, we determined that certain non-compete agreements and customer relationship intangibles were impaired at December 31, 2009. We recorded an impairment charge related to these intangible assets totaling $2,488 in the accompanying statement of operations for the year ended December 31, 2009.

Goodwill:

We evaluated our goodwill and indefinite-lived intangible assets in accordance with the recoverability tests prescribed by U.S. GAAP as of our annual testing date in 2010. With the assistance of a third-party valuation specialist, we prepared several valuation models including a discounted cash flow analysis, a market multiples approach and a review of precedent transactions. We weighted these valuation methodologies, with greatest weight given to our discounted cash flow projections, which included assumptions related to organic growth, capital investment, working capital needs, residual value and other assumptions. Based on this analysis, we determined that our goodwill and indefinite-lived intangible assets were not impaired as of the annual testing date for the year ended December 31, 2010. For the year ended December 31, 2009, we determined that goodwill associated with three of our reporting units was impaired as of the testing date. For the year ended December 31, 2008, we performed this test at the annual testing date and impairment of goodwill was indicated for most of our reporting units. Then, due to a significant decline in the overall U.S. debt and equity markets which was deemed a triggering event, we performed the test at December 31, 2008 and impairment was indicated. We update our assumptions used in the preparation of our discounted cash flow analysis each year based largely upon unobservable inputs from management, which represent our best estimates of actual results over a long-term period, appropriately discounted as of the test date. Although the assumptions used vary from year-to-year based upon our perception of market conditions, the valuation methodology used to value goodwill was consistent for the years ended December 31, 2010, 2009 and 2008.

For the years ended December 31, 2009 and 2008, we performed step two of the goodwill impairment test as prescribed by U.S. GAAP. In performing the two-step goodwill impairment test, we compared the fair value of each of our reportable units to its carrying value. We estimated the fair value of our reportable units by considering both the income approach and market approach. Under the market approach, the fair value of the reportable unit is based on market multiple and recent transaction values of peer companies. Under the income approach, the fair value of the reportable unit is based on the present value of estimated future cash flows using the discounted cash flow method. The discounted cash flow method is dependent on a number of unobservable inputs including projections of the amounts and timing of future revenues and cash flows, assumed discount rates and other assumptions. Based upon this initial testing, we determined that goodwill associated with several of our reporting units within our completion and production services business segments were impaired, which triggered step two. For step two, we calculated the implied fair value of goodwill and compared it to the carrying amount of that goodwill, by examining the fair value of the tangible and intangible property of these reportable units. The inputs for this model were largely unobservable estimates from management based on historical performance. We retained the assistance of a third-party appraiser to collect market data for a sample of assets from each of these reporting units to assess the market value of the property, plant and equipment of these reportable units, and the results were extrapolated to the asset population. Thus, the primary source for our assessment of value was based on management's estimates and projections. The result of this analysis was a calculated goodwill impairment of $97,643 which is recorded in the accompanying statement of operations at December 31, 2009. This impairment charge of $97,643 was allocated to the completion and production services business segment in 2009. These impairments were deemed necessary due to an overall decline in oil and gas exploration and production activity throughout 2009. For the year ended December 31, 2008, goodwill with a carrying amount of $613,876 was written down to its implied fair value of $341,592, resulting in an impairment charge of $272,284, of which $272,006 was recorded as an impairment loss and $277 was recorded as a charge to cumulative translation adjustment in the accompanying balance sheet as of December 31, 2008. We continue to hold an investment in each of these reportable units for which impairment losses were recorded in 2009 and 2008.

The following tabular presentation is presented for quantitative presentation of our significant fair value measurements for the years ended December 31, 2010, 2009 and 2008:

Description	Balance at Year End	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gains (Losses)
As of December 31, 2010:					
Non-monetary exchange	$ 914	—	$ 914	$ —	$ 493
Goodwill	250,533	—	—	250,533	—
	$251,447	—	$ 914	$250,533	$ 493
As of December 31, 2009:					
Non-monetary exchange	$ 4,487	—	$4,487	$ —	$ (4,868)
Property, plant and equipment	100,820	—	—	100,820	(36,158)
Definite-lived intangible assets	187	—	—	187	(2,488)
Goodwill	243,823	—	—	243,823	(97,643)
	$349,317	—	$4,487	$344,830	$(141,157)
As of December 31, 2008:					
Goodwill	$613,876	—	$ —	$341,592	$(272,284)

(u) Investment in Unconsolidated Subsidiaries

We constructed a salt water disposal well for a customer during 2009 at a cost of $1,497. In exchange for this service, we received a non-controlling interest in the company that owns and operates the well. In accordance with U.S. GAAP, we account for our interest in this company as an equity investment in an unconsolidated subsidiary, whereby we have recorded our initial investment as a long-term asset in the accompanying balance sheet at December 31, 2009, and record our portion of earnings or losses associated with this well as equity in earnings of unconsolidated subsidiaries, a component of income or expense in the current period. We have evaluated this ownership interest and determined that it does not constitute a variable interest entity, as that term is defined in current U.S. GAAP guidance. This well did not begin operating until late 2009, and we did not record any significant earnings or loss associated with these operations during the years ended December 31, 2009 or 2010.

3. Business combinations:

We did not acquire any businesses during the year ended December 31, 2009. However, we did execute several business acquisitions for the years ended December 31, 2010 and 2008, as described below, and expect to complete more transactions in the future, depending on the circumstances and the availability of financing.

(a) Acquisitions During the Year Ended December 31, 2010:

During the year ended December 31, 2010, we acquired assets or all of the equity interests in various service companies, for $33,721 in cash, resulting in tax deductible goodwill of $6,710.

(i) On May 11, 2010, we acquired certain assets of a provider of gas lift services based in Oklahoma City, Oklahoma. The total purchase price for the assets was $1,440 in cash. We recorded goodwill totaling $1,017 in conjunction with this acquisition which has been allocated entirely to the completion and production services business segment. We believe this acquisition supplements our plunger lift service offering for the completion and production services business segment.

(ii) On September 3, 2010, we completed the purchase of a well service and fluid handling service provider based in Carrizo Springs, Texas. The total purchase price for the assets was $20,767 and included goodwill of $4,046, all of which was allocated to the completion and production services business segment. We believe this acquisition enhances our position in the Eagle Ford Shale in south Texas.

(iii) On December 1, 2010, we completed the purchase of all of the outstanding common stock of a disposal well operator located in Colorado for $11,514 in cash, subject to an additional $500 holdback. We recorded goodwill totaling $1,457 in conjunction with this acquisition which has been allocated to the completion and production services business segment. We believe this acquisition will enhance our position in the Denver-Julesburg Basin in Colorado.

We accounted for these acquisitions using the purchase method of accounting, whereby the purchase price was allocated to the fair value of net assets acquired, including definite-lived intangible assets and property, plant and equipment, with the excess recorded as goodwill. Results for each of these acquisitions were included in our accounts and results of operations since the date of acquisition. The following table summarizes the preliminary purchase price allocations for these acquisitions as of December 31, 2010:

	Totals
Net assets acquired:	
Accounts receivable	$ 209
Inventory and other current assets	428
Property, plant and equipment	23,960
Payables and accrued liabilities	(106)
Intangible assets	2,520
Goodwill	6,710
Net assets acquired	$33,721
Consideration:	
Cash, net of cash and cash equivalents acquired	$33,721

We determined the fair value of assets and liabilities acquired through these business acquisitions as of the acquisition date by retaining third-party consultants to perform valuation techniques related to identifiable intangible assets and to evaluate property, plant and equipment acquired based upon, at minimum, the replacement cost of the assets, except for the two saltwater disposal wells in Colorado which were newly constructed just prior to acquisition. Working capital items were deemed to have a fair market value equal to book value. Of the total intangible assets acquired, $1,670 related to customer relationship intangibles determined by applying an income approach over the expected term, allowing for customer attrition at an assumed rate.

(b) Acquisitions During the Year Ended December 31, 2008:

During the year ended December 31, 2008, we acquired substantially all the assets or all of the equity interests in four oilfield service companies, for $180,154 in cash, resulting in goodwill of $71,209. Several of these acquisitions were subject to final working capital adjustments.

(i) On February 29, 2008, we acquired substantially all of the assets of KR Fishing & Rental, Inc. ("KR Fishing & Rental") for $9,464 in cash, resulting in goodwill of $6,411. KR Fishing & Rental, Inc. is a provider of fishing, rental and foam unit services in the Piceance Basin and the Raton Basin, and is located in Rangely, Colorado. We believe this acquisition complements our completion and production services business in the Rocky Mountain region.

(ii) On April 15, 2008, we acquired all the outstanding common stock of Frac Source Services, Inc. ("Frac Source"), a provider of pressure pumping services to customers in the Barnett Shale of north Texas, for $62,359 in cash, net of cash acquired, which includes a working capital adjustment of $1,600 and recorded goodwill of $15,431. Upon closing this transaction, we entered into a contract with one of our major customers to provide pressure pumping services in the Barnett Shale utilizing three frac fleets under a contract with a term that extends up to three years from the date each fleet is placed into service. We spent an additional $20,000 in 2008 on capital equipment related to these contracted frac fleets. Thus, our total investment in this operation was approximately $82,400. This acquisition expanded our pressure pumping business in north Texas and the related contract provides a stable revenue stream from which to expand our pressure pumping business outside of this region.

(iii) On October 3, 2008, we acquired all of the membership interests of TSWS Well Services, LLC ("TSWS"), a limited liability corporation which held substantially all of the well servicing and heavy haul assets of TSWS, Inc., a company based in Magnolia, Arkansas, which provides well servicing and heavy haul services to customers in northern Louisiana, east Texas and southern Arkansas. As consideration, we paid $57,163 in cash and prepaid an additional $1,000 related to an employee retention bonus pool. We also recorded goodwill totaling $21,911. This acquisition extended our geographic reach in the Haynesville Shale area.

(iv) On October 4, 2008, we acquired substantially all of the assets of Appalachian Well Services, Inc. and its wholly-owned subsidiary ("AWS"), each of which is based in Shelocta, Pennsylvania. This business provides pressure pumping, e-line and coiled tubing services in the Appalachian region, and includes a service area which extends through portions of Pennsylvania, West Virginia, Ohio and New York. As consideration for the purchase, we paid $50,168 in cash and issued 588,292 unregistered shares of our common stock, valued at $15.04 per share. We invested an additional $6,500 to complete a frac fleet at this location and have an option to purchase real property for approximately $600. In addition, we entered into an agreement under which we might be required to pay up to an additional $5,000 in cash consideration during the earn-out period. The earn-out period expired in 2010 with no additional consideration required. We recorded goodwill of approximately $27,456 associated with this acquisition, however, this goodwill was deemed impaired in 2009 and expensed as of December 31, 2009. We believe this acquisition created a platform for future growth for our pressure pumping and other completion and production service lines in the Marcellus Shale.

We accounted for these acquisitions using the purchase method of accounting, whereby the purchase price was allocated to the fair value of net assets acquired, including definite-lived intangible assets and property, plant and equipment at depreciated replacement costs, with the excess recorded as goodwill. Results for each of these acquisitions were included in our accounts and results of operations since the date of acquisition, and goodwill associated with these acquisitions was allocated entirely to the completion and production services business segment. The following table summarizes our purchase price allocations for these acquisitions as of December 31, 2008:

	KR Fishing & Rental	Frac Source	TSWS	AWS	Totals
Net assets acquired:					
Property, plant and equipment	$2,673	$41,172	$28,852	$24,140	$ 96,837
Non-cash working capital	50	(2,085)	1,000	3,226	2,191
Intangible assets	330	6,810	6,400	4,200	17,740
Deferred tax asset	—	1,031	—	—	1,031
Goodwill	6,411	15,431	21,911	27,456	71,209
Net assets acquired	$9,464	$62,359	$58,163	$59,022	$189,008
Consideration:					
Cash, net of cash and cash equivalents acquired	$9,464	$62,359	$58,163	$50,168	$180,154
Stock issued for acquisition	—	—	—	8,854	8,854
Total consideration	$9,464	$62,359	$58,163	$59,022	$189,008

Of the $71,209 of goodwill above, $55,718 is tax deductible.

The purchase price of each of the businesses that we acquire is negotiated as an arm's length transaction with the seller. We generally evaluate acquisition targets based on an earnings multiple approach, whereby we consider precedent transactions which we have undertaken and those of others in our industry.

We determined the fair value of assets and liabilities acquired through these business acquisitions as of the acquisition date by retaining third-party consultants to perform valuation techniques related to identifiable intangible assets and to evaluate property, plant and equipment acquired based upon, at minimum, the replacement cost of the assets. Working capital items were deemed to have a fair market value equal to book value. Of the total intangible assets acquired, $14,010 related to customer relationship intangibles determined by applying an income approach over the expected term, allowing for customer attrition at an assumed rate. We considered these factors when determining the goodwill impairment recorded at December 31, 2008. Of the businesses acquired in 2008, an insignificant portion of the goodwill associated with the acquisitions of TSWS and AWS was deemed impaired at December 31, 2008. As of December 31, 2009, the remaining goodwill associated with AWS, and other intangibles totaling $2,488, were deemed impaired and expensed.

(c) *Pro Forma Results*

Our acquisitions during the year ended December 31, 2010 were not deemed to be significant to our overall results for the year. Therefore, no pro forma disclosure of the impact of these acquisitions has been provided for 2010.

We calculated the pro forma impact of the businesses we acquired on our operating results for the year ended December 31, 2008. The following pro forma results give effect to each of these acquisitions, assuming that each occurred on January 1, 2008.

We derived the pro forma results of these acquisitions based upon historical financial information obtained from the sellers and certain management assumptions. In addition, we assumed debt service costs related to these acquisitions based upon the actual cash investments, calculated at a rate of 7% per annum, less an assumed tax benefit calculated at our statutory rate of 35%. Each of these acquisitions related to our continuing operations, and, thus, had no pro forma impact on discontinued operations presented on the accompanying statement of operations for the year ended December 31, 2008.

The following pro forma results do not purport to be indicative of the results that would have been obtained had the transactions described above been completed on the indicated dates or that may be obtained in the future.

	Pro Forma Results For the Year Ended December 31, 2008 (Unaudited)
Revenue	$1,901,879
Loss before taxes	$ (2,132)
Net loss from continuing operations	$ (78,203)
Net loss	$ (83,062)
Loss per share:	
Basic	$ (1.13)
Diluted	$ (1.13)

4. Accounts receivable:

	2010	2009
Trade accounts receivable	$253,662	$155,871
Related party receivables(a)	51,046	6,593
Unbilled revenue	42,747	19,409
Notes and other receivables	2,353	1,975
	349,808	183,848
Allowance for doubtful accounts	4,160	12,564
	$345,648	$171,284

(a) See Note 19, "Related party transactions."

The following table summarizes the change in our allowance for doubtful accounts for the years ended December 31, 2010, 2009 and 2008:

Year Ended	Balance at Beginning of Period	Additions Charged to Expense	Write-offs or Adjustments	Balance at End of Period
2010	$12,564	$ (159)	$(8,245)	$ 4,160
2009	$ 5,976	$10,770	$(4,182)	$12,564
2008	$ 5,487	$ 4,344	$(3,855)	$ 5,976

5. Inventory:

	2010	2009
Finished goods	$18,644	$23,435
Manufacturing parts, materials and fuel	16,063	14,486
Work in process	1,282	431
	35,989	38,352
Inventory reserves	2,453	888
	$33,536	$37,464

6. Property, plant and equipment:

December 31, 2010	Cost	Accumulated Depreciation	Net Book Value
Land	$ 16,153	$ —	$ 16,153
Building	32,083	4,456	27,627
Field equipment	1,434,986	642,302	792,684
Vehicles	128,381	58,110	70,271
Office furniture and computers	18,259	11,970	6,289
Leasehold improvements	26,644	7,538	19,106
Construction in progress	23,898	—	23,898
	$1,680,404	$724,376	$956,028

December 31, 2009	Cost	Accumulated Depreciation	Net Book Value
Land	$ 8,884	$ —	$ 8,884
Building	30,200	3,168	27,032
Field equipment	1,293,292	497,632	795,660
Vehicles	126,256	55,035	71,221
Office furniture and computers	17,087	9,108	7,979
Leasehold improvements	25,006	4,771	20,235
Construction in progress	10,122	—	10,122
	$1,510,847	$569,714	$941,133

Construction in progress at December 31, 2010 and 2009 primarily included progress payments to vendors for equipment to be delivered in future periods and component parts to be used in final assembly of operating equipment, which in all cases were not yet placed into service at the time. For the years ended December 31, 2010, 2009 and 2008, we recorded capitalized interest of $1,250, $878 and $4,458, respectively, related to assets that we are constructing for internal use and amounts paid to vendors under progress payments for assets that are being constructed on our behalf.

Effective March 1, 2009, our Canadian subsidiary transferred certain property, plant and equipment used in our production testing business to Enseco, a competitor, in exchange for certain electric line (e-line) equipment. This exchange was determined to have commercial substance for us and therefore we recorded the new assets acquired at the fair market value of the assets surrendered which had a carrying value of $9,284. We incurred costs to sell totaling approximately $71. We determined the fair value of the assets with the assistance of a third-party appraiser, assuming an orderly liquidation methodology, to be $4,487, resulting in a loss on the exchange of $4,868. Of the total value assigned to the new assets, $4,209 was included in property, plant and equipment and $279 was included in inventory in the accompanying balance sheet as of December 31, 2009. The fair market value of the assets received was determined to be $5,497, using the same methodology applied to the assets surrendered. We believe that these e-line assets will generate cash flows in excess of the cash flows that would have been received from the production testing assets due to relatively higher demand from our customers for e-line services.

Effective March 31, 2009, we entered into a sale-leaseback transaction with Agua Dulce, LLC, through which we sold a facility and approximately 50 acres of real property located near Rock Springs, Wyoming for $3,827. The sales price approximated the net book value of the facility, which is currently under construction, and the land, resulting in an insignificant gain on the transaction which has been included as a component of selling, general and administrative expense in the accompanying statement of operations for the year ended December 31, 2009. In addition, the buyer agreed to fund the completion of the construction of the facility. Effective April 1, 2009, we became party to the lease agreement which requires monthly operating lease payments for a term of 10 years, with an option to extend the lease term for an additional 10 years. The rental rate adjusts for construction draws to date divided ratably over the remaining lease term. The lease term began on April 1, 2009 and the first monthly rental was $35. We will also incur additional lease costs related to certain operating costs, taxes and insurance for the facility over the term of the lease.

Effective July 30, 2009, we entered into a sale-leaseback agreement with Enterprise Leasing Company of Houston to sell over 550 light-vehicles with a net book value of approximately $10,362 as of July 30, 2009. During the third quarter of 2009, we received proceeds from the sale which totaled $10,551. In August 2009, pursuant to this lease agreement, we began making monthly rental payments of approximately $306. The lease terms range from 24 to 36 months.

7. Intangible assets:

		As of December 31, 2010			As of December 31, 2009		
Description	Term	Historical Cost	Accumulated Amortization	Net Book Value	Historical Cost	Accumulated Amortization	Net Book Value
	(In months)						
Patents and trademarks	60 to 120	$ 5,215	$ 3,353	$1,862	$ 5,942	$ 2,421	$ 3,521
Contractual agreements	24 to 120	11,985	8,660	3,325	9,455	6,644	2,811
Customer lists and other	36 to 60	13,302	9,280	4,022	13,322	6,411	6,911
Totals		$30,502	$21,293	$9,209	$28,719	$15,476	$13,243

We recorded amortization expense associated with intangible assets of continuing operations totaling $6,591, $7,769 and $5,248 for the years ended December 31, 2010, 2009 and 2008, respectively. We expect to record amortization expense associated with these intangible assets for the next five years approximating: 2011 — $4,645; 2012 — $2,926; 2013 — $1,341; 2014 — $170 and 2015 — $127.

8. Deferred financing costs:

	Cost	Accumulated Amortization	Net Book Value
December 31, 2010			
Deferred financing costs	$19,010	$9,316	$ 9,694
December 31, 2009			
Deferred financing costs	$19,010	$6,266	$12,744

We incurred deferred financing costs associated with our amended credit facility as well as $13,414 related to the issuance of our senior notes in December 2006. In October 2009, we amended our senior secured credit facility and incurred additional financing costs of $2,911 in the fourth quarter of 2009. In October 2009, due to the decrease in borrowing capacity after giving effect to the amendment, we expensed $528 of unamortized fees related to our prior revolving credit facilities.

9. Taxes:

Tax expense (benefit) from continuing operations consisted of:

	2010	2009	2008
Domestic:			
Current income taxes	$ (105)	$(59,637)	$42,490
Deferred income taxes	48,468	(4,733)	24,739
	48,363	(64,370)	67,229
Foreign:			
Current income taxes	3,844	4,116	8,988
Deferred income taxes	(627)	(2,834)	(3,912)
	3,217	1,282	5,076
Tax expense (benefit) — continuing operations	$51,580	$(63,088)	$72,305

We operate in several tax jurisdictions. A reconciliation of the U.S. federal income tax rate of 35% for the years ended December 31, 2010, 2009 and 2008 to our effective income tax rate follows:

	2010	2009	2008
Expected provision for taxes:	$47,508	$(85,665)	$ (4,341)
Increase (decrease) resulting from foreign tax rate differential	(528)	(1,971)	280
Change in foreign tax rates	—	68	746
Change in domestic tax rates	1,357	4,544	—
State taxes, net of federal benefit	978	(4,948)	4,989
Non-deductible expenses	2,180	18,125	70,619
Other, net	85	6,759	12
Tax expense (benefit) — continuing operations	$51,580	$(63,088)	$72,305

Non-deductible expenses for the years ended December 31, 2009 and 2008 relate primarily to impaired goodwill with limited tax basis. There was no goodwill impairment for the year ended December 31, 2010.

The net deferred income tax liability was comprised of the tax effect of the following temporary differences:

	2010	2009
Deferred income tax assets:		
Net operating loss	$ 10,386	$ 6,909
Goodwill and intangible assets	9,240	14,487
Accrued liabilities and other	6,789	4,853
Stock-based compensation costs	4,125	6,744
	30,540	32,993
Less valuation allowance	(253)	(265)
	30,287	32,728
Deferred income tax liabilities:		
Property, plant and equipment	(213,589)	(168,450)
Other	(4,621)	(4,360)
	(218,210)	(172,810)
Net deferred income tax liability	$(187,923)	$(140,082)

The net deferred income tax liability consisted of:

	2010	2009
Domestic	$(187,988)	$(139,061)
Foreign	65	(1,021)
	$(187,923)	$(140,082)

Included in our deferred tax assets are state tax net operating loss carry forwards of $9,279. We expect to generate future state taxable income to fully utilize these loss carry forwards.

We had no U.S. federal loss carry forward at December 31, 2010 and $3,592 of U.S. loss carry forward at December 31, 2009. We have $1,107 of foreign non-capital loss carry forward at December 31, 2010, compared to $2,930 at December 31, 2009.

No deferred income taxes were provided on $28,584 of undistributed earnings of foreign subsidiaries as of December 31, 2010, as we intend to indefinitely reinvest these funds. Upon distribution of these earnings in the form of dividends or otherwise, we may be subject to U.S. income taxes and foreign withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable on the eventual distribution of these earnings after consideration of available foreign tax credits.

We adopted the FASB interpretation on accounting for uncertainty in income taxes as of January 1, 2007. This guidance clarifies the accounting for uncertain tax positions that may have been taken by an entity. Specifically, it prescribes a more-likely-than-not recognition threshold to measure a tax position taken or expected to be taken in a tax return through a two-step process: (1) determining whether it is more likely than not that a tax position will be sustained upon examination by taxing authorities, after all appeals, based upon the technical merits of the position; and (2) measuring to determine the amount of benefit/expense to recognize in the financial statements, assuming taxing authorities have all relevant information concerning the issue. The tax position is measured at the largest amount of benefit/expense that is greater than 50 percent likely of being realized upon ultimate settlement. This pronouncement also specifies how to present a liability for unrecognized tax benefits in a classified balance sheet, but does not change the classification requirements for deferred taxes. Under this guidance, if a tax position previously failed the more-likely-than-not recognition threshold, it should be recognized in the first subsequent financial reporting period in which the threshold is met. Similarly, a position that no longer meets this recognition threshold should no longer be recognized in the first financial reporting period in which the threshold is no longer met.

The FASB issued additional guidance on how an entity is to determine whether a tax position has effectively settled for purposes of recognizing previously unrecognized tax benefits. Specifically, this guidance states that an entity would recognize a benefit when a tax position is effectively settled using the following criteria: (1) the taxing authority has completed its examination including all appeals and administrative reviews; (2) the entity does not plan to appeal or litigate any aspect of the tax position; and (3) it is remote that the taxing authority would examine or reexamine any aspect of the tax position, assuming the taxing authority has full knowledge of all relevant information relative to making their assessment on the position.

We performed an examination of our tax positions and calculated the cumulative amount of our estimated exposure by evaluating each issue to determine whether the impact exceeded the 50 percent threshold of being realized upon ultimate settlement with the taxing authorities. Based upon this examination, we determined that the aggregate exposure did not have a material impact on our financial statements during the years ended December 31, 2010, 2009 and 2008. Therefore, we have not recorded an adjustment to our financial statements related to this interpretation. We will continue to evaluate our tax positions, and recognize any future impact as a charge to income in the applicable period in accordance with the standard. Our tax filings for tax years 2006 to 2009 remain open for examination by taxing authorities. We do not anticipate any significant changes in our uncertain tax positions during the next twelve months.

Our accounting policy related to income tax penalties and interest assessments is to accrue for these costs and record a charge to selling, general and administrative expense for tax penalties and a charge to interest expense for interest assessments during the period that we take an uncertain tax position through resolution with the taxing authorities or the expiration of the applicable statute of limitations. We did not record any significant amounts related to penalties and interest during the years ended December 31, 2010, 2009 and 2008.

10. Notes payable:

We entered into a note arrangement to finance certain of our annual insurance premiums for the policy term from December 1, 2007 to April 30, 2009. Effective May 1, 2009, we renewed our insurance policies and entered into a similar financing arrangement for the twelve-month policy term which extended through April 2010. Concurrently, we renewed our workers' compensation, general liability and auto insurance policies through our insurance broker for the same policy term. Our accounting policy has been to record a prepaid asset associated with certain of these policies which is amortized over the term and which takes into account actual premium payments and deposits made to date, to record an accrued liability for premiums which are contractually committed for the policy term and to make monthly premium payments in accordance with our premium commitments and monthly note payments for amounts financed. Effective May 1, 2010, we renewed our annual insurance premiums for the policy term May 1, 2010 through April 30, 2011, but chose to prepay our premiums for certain insurance coverages which had been financed through a note arrangement in prior renewals, and to continue to make monthly premium payments through our broker for other insurance coverages, including workers' compensation, general liability and auto insurance during this twelve-month policy term. As a result, we recorded a prepaid asset of $4,267 in May 2010 associated with these renewals.

11. Long-term debt:

The following table summarizes long-term debt as of December 31, 2010 and 2009:

	2010	2009
U.S. revolving credit facility(a)	$ —	$ —
Canadian revolving credit facility(a)	—	—
8% senior notes(b)	650,000	650,000
Capital leases and other	—	230
	650,000	650,230
Less: current maturities of long-term debt and capital leases	—	228
	$650,000	$650,002

(a) We maintain a senior secured facility (the "Credit Agreement") with Wells Fargo Bank, National Association, as U.S. Administrative Agent, HSBC Bank Canada, as Canadian Administrative Agent, and certain other financial institutions. On October 13, 2009, we entered into the Third Amendment (the Credit Agreement after giving effect to the Third Amendment, the "Amended Credit Agreement") and modified the structure of our existing credit facility to an asset-based facility subject to borrowing base restrictions. In connection with the Third Amendment, Wells Fargo Capital Finance, LLC (formerly known as Wells Fargo Foothill, LLC) replaced Wells Fargo Bank, National Association, as U.S. Administrative Agent and also serves as U.S. Issuing Lender and U.S. Swingline Lender under the Amended Credit Agreement. The Amended Credit Agreement provides for a U.S. revolving credit facility of up to $225,000 that matures in December 2011 and a Canadian revolving credit facility of up to $15,000 (with Integrated Production Services Ltd., one of our wholly-owned subsidiaries, as the borrower thereof ("Canadian Borrower")) that matures in December 2011. The Amended Credit Agreement includes a provision for a "commitment increase", as defined therein, which permits us to effect up to two separate increases in the aggregate commitments under the Amended Credit Agreement by designating one or more existing lenders or other banks or financial institutions, subject to the bank's sole discretion as to participation, to provide additional aggregate financing up to $75,000, with each committed increase equal to at least $25,000 in the U.S., or $5,000 in Canada, and in accordance with other provisions as stipulated in the Amended Credit Agreement. Certain portions of the credit facilities are available to be borrowed in U.S. dollars, Canadian dollars and other currencies approved by the lenders.

Our U.S. borrowing base is limited to: (1) 85% of U.S. eligible billed accounts receivable, less dilution, if any, plus (2) the lesser of 55% of the amount of U.S. eligible unbilled accounts receivable or $10.0 million, plus (3) the lesser of the "equipment reserve amount" and 80% times the most recently determined "net liquidation percentage", as defined in the Amended Credit Agreement, times the value of our and the U.S. subsidiary guarantors' equipment, provided that at no time shall the amount determined under this clause exceed 50% of the U.S. borrowing base, minus (4) the aggregate sum of reserves established by the U.S. Administrative Agent, if any. The "equipment reserve amount" means $50.0 million upon the effective date of the Third Amendment, less $0.6 million for each subsequent month, not to be reduced below zero in the aggregate.

The Canadian borrowing based is limited to: (1) 80% of Canadian eligible billed accounts receivable, plus (2) if the Canadian Borrower has requested credit for equipment under the Canadian borrowing base, the lesser of (a) $15.0 million, and (b) 80% times the most recently determined "net liquidation percentage", as defined in the Amended Credit Agreement, times the value (calculated on a basis consistent with our historical accounting practices) of our and the US subsidiary guarantors' equipment, minus (3) the aggregate amount of reserves established by our Canadian Administrative Agent, if any.

Subject to certain limitations set forth in the Amended Credit Agreement, we have the ability to elect how interest under the Amended Credit Agreement will be computed. Interest under the Amended Credit Agreement may be determined by reference to (1) the London Inter-bank Offered Rate, or LIBOR, plus an applicable margin between 3.75% and 4.25% per annum (with the applicable margin depending upon our "excess availability amount", as defined in the Amended Credit Agreement) or (2) the "Base Rate" (which means the higher of the Prime Rate, Federal Funds Rate plus 0.50%, 3-month LIBOR plus 1.00% and 3.50%), plus the applicable margin, as described above. For the period from the effective date of the Third Amendment until the six month anniversary of the effective date of the Third Amendment, interest was computed with an applicable margin rate of 4.00%. If an event of default exists or continues under the Amended Credit Agreement, advances will bear interest as described above with an applicable margin rate of 4.25% plus 2.00%. Additionally, if an event of default exists under the Amended Credit Agreement, as defined therein, the lenders could accelerate the maturity of the obligations outstanding thereunder and exercise other rights and remedies. Interest is payable monthly.

Under the Amended Credit Agreement, we are permitted to prepay our borrowings and we have the right to terminate, in whole or in part, the unused portion of the U.S. commitments in $1.0 million increments upon written notice to the U.S. Administrative Agent. If all of the U.S. facility is terminated, the Canadian facility must also be terminated.

All of the obligations under the U.S. portion of the Amended Credit Agreement are secured by first priority liens on substantially all of our assets and the assets of our U.S. subsidiaries as well as a pledge of approximately 66% of the stock of our first-tier foreign subsidiaries. Additionally, all of the obligations under the U.S. portion of the Amended Credit Agreement are guaranteed by substantially all of our U.S. subsidiaries. The obligations under the Canadian portion of the Amended Credit Agreement are secured by first priority liens on substantially all of our assets and the assets of our subsidiaries (other than our Mexican subsidiary). Additionally, all of the obligations under the Canadian portion of the Amended Credit Agreement are guaranteed by us as well as certain of our subsidiaries.

The Amended Credit Agreement also contains various covenants that limit our and our subsidiaries' ability to: (1) grant certain liens; (2) incur additional indebtedness; (3) make certain loans and investments; (4) make capital expenditures; (5) make distributions; (6) make acquisitions; (7) enter into hedging transactions; (8) merge or consolidate; or (9) engage in certain asset dispositions. The Amended Credit Agreement contains one financial maintenance covenant which requires us and our subsidiaries, on a consolidated basis, to maintain a "fixed charge coverage ratio", as defined in the Amended Credit Agreement, of not less than 1.10 to 1.00. This covenant is only tested if our "excess availability amount", as defined under the Amended Credit Agreement, plus certain qualified cash and cash equivalents (collectively "Liquidity") is less than $50.0 million for a period of 5 consecutive days and continues only until such time as our Liquidity has been greater than or equal to $50.0 million for a period of 90 consecutive days or greater than or equal to $75.0 million for a period of 45 consecutive days.

Our fixed charge coverage ratio covenant is calculated, for fiscal quarters ending after September 30, 2009, as the ratio of "EBITDA" calculated for the four fiscal quarter period ended after September 30, 2009 minus capital expenditures made with cash (to the extent not already incurred in a prior period) or incurred during such four quarter period, compared to "fixed charges", calculated for the four quarters then ended. "EBITDA" is defined in the Amended Credit Agreement as consolidated net income for the period plus, to the extent deducted in determining our consolidated net income, interest expense, taxes, depreciation, amortization and other non-cash charges for such period, provided that EBITDA shall be subject to pro forma adjustments for acquisitions and non-ordinary course asset sales assuming that such transactions occurred on the first day of the determination period, which adjustments shall be made in accordance with the guidelines for pro forma presentations set forth by the Securities and Exchange Commission. "Fixed charges", as defined in the Amended Credit Agreement, include interest expense, among other things, reduced by the amortization of transaction fees associated with the Third Amendment.

We were not subject to the fixed charge coverage ratio covenant in the Amended Credit Agreement as of December 31, 2010 since the Excess Availability Amount plus Qualified Cash Amount (each as defined in the

Amended Credit Agreement) exceeded $50,000. If we had been subject to the fixed charge coverage ratio covenant at December 31, 2010, we would have been in compliance.

There were no borrowings outstanding under our U.S. or Canadian revolving credit facilities as of December 31, 2010. There were letters of credit outstanding under the U.S. revolving portion of the facility totaling $26,370, which reduced the available borrowing capacity as of December 31, 2010. We incurred fees related to our letters of credit as of December 31, 2010 at 3.75% per annum. For the twelve months ended December 31, 2010, fees related to our letters of credit were calculated using a 360-day provision, at 4.0% per annum. The availability of the U.S. and Canadian revolving credit facilities is determined by our borrowing base less any borrowings and letters of credit outstanding. The net excess availability under our borrowing base calculations for the U.S. and Canadian revolving facilities at December 31, 2010 was $187,380 and $8,405, respectively.

The primary purpose of our letters of credit is to secure potential future claim liability which may be incurred by our insurance providers. During the quarter ended September 30, 2010, we negotiated a reduction in our letter of credit requirements of $5,569. In addition, we placed $17,000 in escrow as a compensating balance, effectively cash collateralizing a portion of our letters of credit, in order to better utilize excess cash and reduce interest expense. This compensating balance has been recorded as a long-term asset called "Restricted cash" on the accompanying consolidated balance sheet at December 31, 2010.

We incur unused commitment fees under the Amended Credit Agreement ranging from 0.50% to 1.00% based on the average daily balance of amounts outstanding. The unused commitment fees were calculated at 1.00% as of December 31, 2010.

(b) On December 6, 2006, we issued 8.0% senior notes with a face value of $650,000 through a private placement of debt. These notes mature in 10 years, on December 15, 2016, and require semi-annual interest payments, paid in arrears and calculated based on an annual rate of 8.0%, on June 15 and December 15, of each year, which commenced on June 15, 2007. There was no discount or premium associated with the issuance of these notes. The senior notes are guaranteed by all of our current domestic subsidiaries. The senior notes have covenants which, among other things: (1) limit the amount of additional indebtedness we can incur; (2) limit restricted payments such as a dividend; (3) limit our ability to incur liens or encumbrances; (4) limit our ability to purchase, transfer or dispose of significant assets; (5) limit our ability to purchase or redeem stock or subordinated debt; (6) limit our ability to enter into transactions with affiliates; (7) limit our ability to merge with or into other companies or transfer all or substantially all of our assets; and (8) limit our ability to enter into sale and leaseback transactions. We have the option to redeem all or part of these notes on or after December 15, 2011. Additionally, we may redeem some or all of the notes prior to December 15, 2011 at a price equal to 100% of the principal amount of the notes plus a make-whole premium.

Pursuant to a registration rights agreement with the holders of our 8.0% senior notes, on June 1, 2007, we filed a registration statement on Form S-4 with the SEC which enabled these holders to exchange their notes for publicly registered notes with substantially identical terms. These holders exchanged 100% of the notes for publicly traded notes on July 25, 2007. On August 28, 2007, we entered into a supplement to the indenture governing the 8.0% senior notes, whereby additional domestic subsidiaries became guarantors under the indenture. Effective April 1, 2009, we entered into a second supplement to this indenture whereby additional domestic subsidiaries became guarantors under the indenture.

12. Stockholders' equity:

(a) Authorized Share Capital:

On September 12, 2005, our authorized share capital was increased to 200,000,000 shares of common stock from 24,000,000 shares of common stock with par value of $0.01 per share and to 5,000,000 shares of preferred stock from 1,000 shares of preferred stock with a par value of $0.01 per share.

(b) Initial Public Offering:

On April 26, 2006, we sold 13,000,000 shares of our common stock, $.01 par value per share, in our initial public offering. These shares were offered to the public at $24.00 per share, and we recorded proceeds of approximately $292,500 after underwriter fees of $19,500. In addition, we incurred transaction costs of $3,865 associated with the issuance that were netted against the proceeds of the offering. Our stock began trading on the New York Stock Exchange on April 21, 2006.

(c) Stock-based Compensation:

We maintain option plans under which we grant stock-based compensation to employees, officers and directors to purchase our common stock. The exercise price of each option is based on the fair value of the issuing company's common stock at the date of grant. Options may be exercised over a five or ten-year period and generally a third of the options vest on each of the first three anniversaries from the grant date. Upon exercise of stock options, we issue our common stock.

For grants of stock-based compensation on or after January 1, 2006, we apply the prospective transition method prescribed by U.S. GAAP, whereby we recognize expense associated with new awards of stock-based compensation ratably, as determined using a Black-Scholes pricing model, over the expected term of the award.

In November 2006, we assumed the stock option plan of Pumpco, which included 145,000 outstanding employee stock options at an exercise price of $5.00 per share. The exercise price of these stock options was $5.00 per share, which was below market price at the date of grant pursuant to the agreed-upon conversion rate negotiated as part of the acquisition. These options vested ratably over the three-year term. Upon exercise of these Pumpco stock options, we issue shares of our common stock.

(i) Employee Stock Options Granted Between October 1, 2005 and December 31, 2005:

For grants of stock-based compensation between October 1, 2005 and December 31, 2005, we have utilized the modified prospective transition method to record expense associated with these stock-based compensation instruments. Under this transition method, beginning January 1, 2006, we began to recognize expense related to these option grants over the applicable vesting period, with expense calculated by applying a Black-Scholes pricing model with the following assumptions: risk-free rate of 4.23% to 4.47%; expected term of 4.5 years and no dividend rate. The weighted average fair value of these option grants was $2.05 per share.

For the year ended December 31, 2008, the compensation expense recognized related to these stock options was $270, which reduced net income by $174. There was no impact on basic and diluted earnings per share from continuing operations as reported for the year ended December 31, 2008 attributable to the compensation expense recognized related to these stock options. These awards were 100% vested at December 31, 2008.

(ii) Employee Stock Options Granted On or After January 1, 2006:

For grants of stock-based compensation on or after January 1, 2006, we apply the prospective transition method prescribed by U.S. GAAP, whereby we recognize expense associated with new awards of stock-based compensation ratably, as determined using a Black-Scholes pricing model, over the expected term of the award.

During the years ended December 31, 2010 and 2009, the Compensation Committee of our Board of Directors authorized and issued to our officers and employees 480,300 and 875,300 employee stock options, respectively, and 774,800 and 1,191,400 non-vested restricted shares, respectively. The stock options granted on January 29, 2010 had an exercise price of $12.53 per share. Stock option grants in 2009 had an exercise price which ranged from $6.41 to $6.78 per share. The exercise price represented the fair market value of the shares on the date of grant. These stock option grants vest ratably over a three-year term. In addition, our directors received stock option grants during 2010 and 2009 of 30,000 and 40,000 shares, respectively, which vest ratably over a three-year period. Furthermore, the directors received

34,296 shares of non-vested restricted stock in 2010 which vests 100% on January 29, 2011 and received 109,608 shares of non-vested restricted stock in 2009 which vested 100% on January 30, 2010. The fair value of the stock option grants was determined by applying a Black-Scholes option pricing model based on the following assumptions:

Assumptions:	For the Year Ended December 31, 2010	2009
Risk-free rate	1.38% to 2.34%	0.89% to 2.51%
Expected term (in years)	3.7 to 5.1	2.2 to 5.1
Volatility	50%	29% to 47%
Calculated fair value per option	$4.83 to $5.81	$1.14 to $3.01

The weighted average fair value of stock option grants for the years ended December 31, 2010, 2009 and 2008 was $5.74, $1.82 and $4.62, respectively.

For stock option grants made prior to the second quarter of 2008, we did not have sufficient historical market data in order to determine the volatility of our common stock. In accordance with U.S. GAAP, we analyzed the market data of peer companies and calculated an average volatility factor based upon changes in the closing price of these companies' common stock for a three-year period. This volatility factor was then applied as a variable to determine the fair value of our stock option grants. For stock options granted during or after the second quarter of 2008, we calculated an average volatility factor for our common stock for the period from April 21, 2006 through the respective quarter end, or for the three-year period then ended. These volatility calculations were used to compute the calculation of the fair market value of stock option grants made subsequent to June 30, 2008.

We projected a rate of stock option forfeitures based upon historical experience and management assumptions related to the expected term of the options. After adjusting for these forfeitures, we expect to recognize expense totaling $19,538 related to our stock option grants made after January 1, 2006. For the years ended December 31, 2010, 2009 and 2008, we have recognized expense related to these stock option grants totaling $2,321, $3,943 and $5,166, respectively, which represents a reduction of net income before taxes. The impact on net income (loss) was a reduction of $1,439, $2,926 and $3,332, respectively. The unrecognized compensation costs related to the non-vested portion of these awards was $2,418 as of December 31, 2010 and will be recognized over the applicable remaining vesting periods.

The non-vested restricted shares were granted at fair value on the date of grant. If the restricted non-vested shares are not forfeited, we will recognize compensation expense related to our 2010, 2009 and 2008 grants to officers and employees totaling $9,781, $7,634 and $14,025, respectively, over the three-year vesting period. We expect to recognize expense associated with grants to our directors in 2010, 2009 and 2008 totaling $430, $703 and $402, respectively, over a twelve-month vesting period.

The following tables provide a roll forward of stock options from December 31, 2007 to December 31, 2010 and a summary of stock options outstanding by exercise price range at December 31, 2010:

	Options Outstanding	
	Number	Weighted Average Exercise Price
Balance at December 31, 2007	3,730,761	$13.36
Granted	408,596	$17.90
Exercised	(1,238,819)	$ 9.70
Cancelled	(154,026)	$20.11
Balance at December 31, 2008	2,746,512	$15.33
Granted	915,300	$ 6.41
Exercised	(123,858)	$ 4.01
Cancelled	(154,334)	$20.17
Balance at December 31, 2009	3,383,620	$13.09
Granted	510,300	$12.53
Exercised	(599,035)	$13.49
Cancelled	(153,305)	$18.16
Balance at December 31, 2010	3,141,580	$12.68

	Options Outstanding			Options Exercisable		
Range of Exercise Price	Outstanding at December 31, 2010	Weighted Average Remaining Life (Months)	Weighted Average Exercise Price	Exercisable at December 31, 2010	Weighted Average Remaining Life (months)	Weighted Average Exercise Price
$5.00	65,000	29	$ 5.00	65,000	29	$ 5.00
$6.69 - $8.16	1,386,031	77	$ 6.54	793,276	63	$ 6.63
$11.66 - $12.53	573,569	103	$12.43	63,269	57	$11.66
$15.90	275,400	85	$15.90	176,644	73	$15.90
$17.60 - $19.87	412,011	73	$19.82	412,011	73	$19.82
$22.55 - $24.07	333,069	64	$23.97	333,069	64	$23.97
$26.26 - $27.11	45,000	77	$26.35	45,000	77	$26.35
$29.88	40,000	89	$29.88	26,667	89	$29.88
$34.19	11,500	90	$34.19	7,667	90	$34.19
	3,141,580	80	$12.68	1,922,603	66	$14.32

The total intrinsic value of stock options exercised during the years ended December 31, 2010 and 2009 was $7,888 and $568, respectively. The total intrinsic value of all in-the-money vested outstanding stock options at December 31, 2010 was $29,330. Assuming all stock options outstanding at December 31, 2010 were vested, the total intrinsic value of all in-the-money outstanding stock options would have been $53,394.

(d) 2008 Incentive Award Plan:

In March 2008, upon the recommendation of the Compensation Committee and subject to approval by stockholders, our Board of Directors approved the Complete Production Services, Inc. 2008 Incentive Award Plan, which was intended to succeed the prior stock option plan, the Amended and Restated 2001 Stock Incentive Plan, pursuant to which, 2,500,000 shares of common stock were authorized for future issuance to our directors, officers and employees in conjunction with stock-based compensation arrangements. On May 22, 2008, stockholders owning more than a majority of the shares of our common stock adopted the 2008 Stock Incentive Plan. We subsequently filed a registration statement on Form S-8 and made grants to our directors, officers and employees. In March 2009, upon the recommendation of the Compensation Committee and as approved by our stockholders owning more than a majority of the shares of our common stock on May 24, 2009, we amended the 2008 Incentive Award Plan to increase the number of shares authorized for future issuance to up to 6,400,000 shares. As amended, the aggregate number of shares of common stock available for issuance under the 2008 Incentive Award Plan will be reduced by (i) 1.3 shares for each share of common stock delivered in settlement of any full value award, and (ii) 1.0 shares for each share of common stock delivered in settlement of any option, stock appreciation right or any other award that is not a full value award. If all of the shares authorized by the amendment to the 2008 Incentive Award Plan were granted as full value awards, then there would be 4,900,000 shares granted as full value awards and no shares available for issuance as awards that were not full value awards. For purposes of the 2008 Incentive Award Plan, full value awards mean any award other than (i) an option, (ii) a stock appreciation right or (iii) any other award for which the holder pays the intrinsic value existing as of the date of grant (whether directly or by forgoing a right to receive a payment from us or any subsidiary of ours). We subsequently filed a registration statement on Form S-8 and made grants to our directors, officers and employees under the 2008 Incentive Award Plan, as amended. The 2008 Stock Incentive Plan provides that forfeitures under the Amended and Restated 2001 Stock Incentive Plan will become available for issuance under the 2008 Incentive Award Plan.

(e) Non-vested Restricted Stock:

We present the amortization of non-vested restricted stock as an increase in additional paid-in capital. At December 31, 2010 and 2009, amounts not yet recognized related to non-vested stock totaled $9,704 and $9,727, respectively, which represented the unamortized expense associated with awards of non-vested stock granted to employees, officers and directors under our compensation plans. Compensation expense associated with these grants of non-vested stock is determined as the fair value of the shares on the date of grant, and recognized ratably over the applicable vesting periods. We recognized compensation expense associated with non-vested restricted stock totaling $9,233, $8,222 and $6,934 for the years ended December 31, 2010, 2009 and 2008, respectively.

The following table summarizes the change in non-vested restricted stock from December 31, 2007 to December 31, 2010:

	Non-vested Restricted Stock	
	Number	Weighted Average Grant Price
Balance at December 31, 2007	625,871	$ 9.46
Granted	618,632	$23.32
Vested	(422,461)	$ 9.94
Forfeited	(32,851)	$12.47
Balance at December 31, 2008	789,191	$19.95
Granted	1,301,008	$ 6.41
Vested	(406,880)	$16.75
Forfeited	(47,754)	$ 9.85
Balance at December 31, 2009	1,635,565	$10.27
Granted	809,096	$12.62
Vested	(679,815)	$10.89
Forfeited	(91,992)	$10.89
Balance at December 31, 2010	1,672,854	$11.12

(f) Common Shares Issued for Acquisitions:

On October 4, 2008, we issued 588,292 unregistered shares of our $0.01 par value common stock as a portion of the purchase consideration for Appalachian Well Service, Inc. and its wholly owned subsidiary. See Note 3, "Business combinations". In connection with this issuance, we recorded common stock and additional paid-in capital totaling $8,854, based on an issuance price of $15.04 per share, based on an average of the closing and opening price of our common stock on the business day proceeding and following the acquisition date. The number of shares issued was calculated based upon the agreed-upon purchase price negotiated with the seller.

(g) Treasury shares:

In accordance with the provisions of the 2008 Incentive Award Plan, holders of unvested restricted stock were given the option to either remit to us the required withholding taxes associated with the vesting of restricted stock, or to authorize us to repurchase shares equivalent to the cost of the withholding tax and to remit the withholding taxes on behalf of the holder. Pursuant to this provision, we repurchased the following shares during the year ended December 31, 2010:

Period	Shares Purchased	Average Price Paid per Share	Extended Amount
January 1 — 31, 2010	109,360	$12.53	$1,370
March 1 — 31, 2010	902	14.06	13
April 1 — 30, 2010	426	11.84	5
May 1 — 31, 2010	1,260	14.48	18
June 1 — 30, 2010	355	14.83	4
July 1 — 31, 2010	591	14.38	8
December 1 — 31, 2010	436	29.00	13
	113,330		$1,431

These shares were included as treasury stock at cost in the accompanying balance sheet as of December 31, 2010. We expect to purchase additional shares in the future pursuant to this plan provision.

13. Earnings per share:

We compute basic earnings per share by dividing net income by the weighted average number of common shares outstanding during the period. Diluted earnings per common and potential common share includes the weighted average of additional shares associated with the incremental effect of dilutive employee stock options and non-vested restricted stock, as determined using the treasury stock method prescribed by the FASB guidance on earnings per share. The following table reconciles basic and diluted weighted average shares used in the computation of earnings per share for the years ended December 31, 2010, 2009 and 2008:

	Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Weighted average basic common shares outstanding	76,048	75,095	73,600
Effect of dilutive securities:			
Employee stock options	759	—	—
Non-vested restricted stock	877	—	—
Weighted average diluted common and potential common shares outstanding	77,684	75,095	73,600

For each of the years ended December 31, 2009 and 2008, we incurred a net loss and thus all potential common shares were deemed to be anti-dilutive. We excluded the impact of anti-dilutive potential common shares from the calculation of diluted weighted average shares for the years ended December 31, 2010, 2009 and 2008. If these potential common shares were included, the impact would have been a decrease in weighted average shares outstanding of 194,211 shares, 2,474,169 shares and 1,245,148 shares, respectively, for the years ended December 31, 2010, 2009 and 2008.

14. Discontinued operations:

In May 2008, our Board of Directors authorized and committed to a plan to sell certain business assets located primarily in north Texas which included our product supply stores, certain drilling logistics assets and other completion and production services assets. Although this sale did not represent a material disposition of assets relative to our total assets, the disposal group did represent a significant portion of the assets and operations which were attributable to our product sales business segment for the periods presented, and therefore, was accounted for as a disposal group that is held for sale. We revised our financial statements, in accordance with U.S. GAAP and removed the results of operations of the disposal group from net income from continuing operations, and presented these separately as income from discontinued operations, net of tax, for the accompanying statement of operations for the year ended December 31, 2008. We ceased depreciating the assets of this disposal group in May 2008 and adjusted the net assets to the lower of carrying value or fair value less selling costs, which resulted in a pre-tax charge of approximately $200. In addition, we allocated $11,109 of goodwill associated with the original formation of Complete Production Services, Inc. to this business, and impaired this goodwill as of the date of the transaction. Thus, this amount has been included in the calculation of the loss on the sale of this disposal group.

On May 19, 2008, we completed the sale of the disposal group for $50,150 in cash and we received assets with a fair market value of $7,987. In addition, we retained the receivables and payables associated with the operating results of these entities as of the date of the sale. The carrying value of the related net assets was approximately $51,353 on May 19, 2008, excluding allocated goodwill of $11,109. We recorded a loss of $6,935 associated with the sale of this disposal group, which represents the excess of the carrying value of the assets less selling costs over the sales price and a charge of approximately $2,610 related to income tax on the transaction. The income tax on the disposal was primarily attributable to the $11,109 of allocated goodwill which was non-deductible for tax purposes and resulted in a taxable gain on the disposal. We sold this disposal group to Select Energy Services, L.L.C., an oilfield service company located in Gainesville, Texas which was owned by a former officer of one of our subsidiaries. Pursuant to the agreement, we sublet office space to Select Energy Services, L.L.C., and provided certain administrative functions for a period of one year at an agreed-upon rate for services per hour. Proceeds from the sale of this disposal group were used to repay outstanding borrowings under our U.S. revolving credit facility and for other general corporate purposes.

The following table summarizes operating results for this disposal group for the periods indicated:

	Period January 1, 2008 through May 19, 2008
Revenue	$59,553
Income before taxes	$ 3,330
Net income before loss on disposal in 2008	$ 2,076
Net income loss	$ (4,859)

15. Segment information:

We report segment information based on how our management organizes the operating segments to make operational decisions and to assess financial performance. We evaluate performance and allocate resources based on net income (loss) from continuing operations before net interest expense, taxes, depreciation and amortization, non-controlling interest and impairment loss ("Adjusted EBITDA"). The calculation of Adjusted EBITDA should not be viewed as a substitute for calculations under U.S. GAAP, in particular net income. Adjusted EBITDA is included in this Annual Report on Form 10-K because our management considers it an important supplemental measure of our performance and believes that it is frequently used by securities analysts, investors and other interested parties in the evaluation of companies in our industry, some of which present EBITDA when reporting their results. We regularly evaluate our performance as compared to other companies in our industry that have different financing and capital structures and/or tax rates by using Adjusted EBITDA. In addition, we use Adjusted EBITDA in evaluating acquisition targets. Management also believes that Adjusted EBITDA is a useful tool for measuring our ability to meet our future debt service, capital expenditures and working capital requirements, and Adjusted EBITDA is commonly used by us and our investors to measure our ability to service indebtedness. Adjusted EBITDA is not a substitute for the U.S. GAAP measures of earnings or cash flow and is not necessarily a measure of our ability to fund our cash needs. It should be noted that companies calculate EBITDA (including Adjusted EBITDA) differently and, therefore, EBITDA has material limitations as a performance measure because it excludes interest expense, taxes, depreciation and amortization. Adjusted EBITDA calculated by us may not be comparable to the EBITDA (or Adjusted EBITDA) calculation of another company and also differs from the calculation of EBITDA under our credit facilities (see Note 11 for a description of the calculation of EBITDA under our existing credit facility, as amended). See the table below for a reconciliation of Adjusted EBITDA to operating income (loss) by segment.

We have three reportable operating segments: completion and production services ("C&PS"), drilling services and product sales. The accounting policies of our reporting segments are the same as those used to prepare our consolidated financial statements as of December 31, 2010, 2009 and 2008. Inter-segment transactions are accounted for on a cost recovery basis.

	C&PS	Drilling Services	Product Sales	Corporate	Total
Year Ended December 31, 2010					
Revenue from external customers	$1,354,797	$172,821	$33,775	$ —	$1,561,393
Inter-segment revenues	$ 248	$ 236	$ 5,998	$ (6,482)	$ —
Adjusted EBITDA, as defined	$ 369,826	$ 38,973	$ 5,197	$ (39,088)	$ 374,908
Depreciation and amortization	$ 159,110	$ 18,480	$ 2,211	$ 2,022	$ 181,823
Operating income (loss)	$ 210,716	$ 20,493	$ 2,986	$ (41,110)	$ 193,085
Capital expenditures	$ 156,787	$ 10,950	$ 320	$ 1,862	$ 169,919
As of December 31, 2010					
Segment assets	$1,488,755	$170,944	$35,015	$105,862	$1,800,576
Year Ended December 31, 2009					
Revenue from external customers	$ 897,584	$114,729	$44,081	$ —	$1,056,394
Inter-segment revenues	$ 105	$ 746	$ 8,237	$ (9,088)	$ —
Adjusted EBITDA, as defined	$ 165,787	$ 9,641	$ 7,966	$ (34,313)	$ 149,081
Depreciation and amortization	$ 174,929	$ 21,067	$ 2,460	$ 2,276	$ 200,732
Write-off of deferred financing fees	$ —	$ —	$ —	$ (528)	$ (528)
Fixed asset and other intangible impairment loss	$ 2,488	$ 36,158	$ —	$ —	$ 38,646
Goodwill impairment loss	$ 97,643	$ —	$ —	$ —	$ 97,643
Operating income (loss)	$ (109,273)	$ (47,584)	$ 5,506	$ (36,061)	$ (187,412)
Capital expenditures	$ 30,930	$ 6,680	$ 228	$ 649	$ 38,487
As of December 31, 2009					
Segment assets	$1,292,199	$172,605	$37,270	$ 86,780	$1,588,854
Year Ended December 31, 2008					
Revenue from external customers	$1,541,709	$234,104	$59,102	$ —	$1,834,915
Inter-segment revenues	$ 576	$ 860	$30,358	$ (31,794)	$ —
Adjusted EBITDA, as defined	$ 467,100	$ 58,743	$12,677	$ (38,293)	$ 500,227
Depreciation and amortization	$ 156,298	$ 19,961	$ 2,537	$ 2,401	$ 181,197
Goodwill impairment loss	$ 243,203	$ 27,410	$ 1,393	$ —	$ 272,006
Operating income (loss)	$ 67,599	$ 11,372	$ 8,747	$ (40,694)	$ 47,024
Capital expenditures	$ 211,648	$ 34,253	$ 6,244	$ 1,631	$ 253,776
As of December 31, 2008					
Segment assets	$1,631,875	$251,015	$52,048	$ 52,415	$1,987,353

Inter-segment sales in 2010, 2009 and 2008 were largely due to service work performed and drilling rigs assembled by a subsidiary in the product sales business segment that provided these services and rigs to a subsidiary in the drilling services business segment as well as other subsidiaries primarily in the completion and production services business segment.

We do not allocate net interest expense or tax expense to the operating segments. The write-off of deferred financing fees of $528 for the year ended December 31, 2009 reduced Adjusted EBITDA, as defined, for the Corporate and Other segment. The following table reconciles operating income (loss) as reported above to net income from continuing operations for each of the years ended December 31, 2010, 2009 and 2008.

	2010	2009	2008
Segment operating income (loss)	$193,085	$(187,412)	$ 47,024
Interest expense	57,669	56,895	59,729
Interest income	(322)	(79)	(301)
Income taxes	51,580	(63,088)	72,305
Write-off of deferred financing fees	—	528	—
Net income (loss) from continuing operations	$ 84,158	$(181,668)	$(84,709)

The following table summarizes the changes in the carrying amount of goodwill for continuing operations by segment for the three-year period ended December 31, 2010:

	C&PS	Drilling Services	Product Sales	Total
Balance at December 31, 2007	$ 512,363	$ 32,973	$ 3,794	$ 549,130
Acquisitions	71,209	—	—	71,209
Impairment charge(a)	(243,481)	(27,410)	(1,393)	(272,284)
Contingency adjustment and other	(128)	—	—	(128)
Foreign currency translation	(6,335)	—	—	(6,335)
Balance at December 31, 2008	$ 333,628	$ 5,563	$ 2,401	$ 341,592
Impairment charge(a)	(97,643)	—	—	(97,643)
Contingency adjustment and other	(126)	—	—	(126)
Balance at December 31, 2009	$ 235,859	$ 5,563	$ 2,401	$ 243,823
Acquisitions	6,710	—	—	6,710
Balance at December 31, 2010	$ 242,569	$ 5,563	$ 2,401	$ 250,533

(a) We evaluate goodwill for impairment annually, or more often if indicators of impairment exist. For the year ending December 31, 2008, we determined that goodwill associated with our Canadian reportable unit was impaired as of the annual test date. Furthermore, due to the decline in the U.S. debt and equity markets, as well as the credit market, we re-performed the prescribed impairment testing at December 31, 2008 and noted impairment which impacted several of our reportable units. Therefore, we recorded an impairment charge of $272,006 for the year ended December 31, 2008. For the year ending December 31, 2009, we determined that goodwill associated with several of our reportable units was also impaired so we recorded an impairment charge of $97,643. See Note 2, "Significant accounting policies — Fair value measurements."

Geographic information (b):

	United States	Canada	Other International	Total
Year Ended December 31, 2010				
Revenue by sale origin to external customers	$1,398,091	$ 81,190	$ 82,112	$1,561,393
Income from continuing operations before taxes	$ 123,595	$ 1,255	$ 10,888	$ 135,738
December 31, 2010				
Long-lived assets	$1,190,545	$ 34,256	$ 23,865	$1,248,666
Year Ended December 31, 2009				
Revenue by sale origin to external customers	$ 910,297	$ 55,514	$ 90,583	$1,056,394
Income (loss) from continuing operations before taxes	$ (254,884)	$(11,069)	$ 21,197	$ (244,756)
December 31, 2009				
Long-lived assets	$1,151,320	$ 40,577	$ 27,031	$1,218,928
Year Ended December 31, 2008				
Revenue by sale origin to external customers	$1,647,176	$ 86,250	$101,489	$1,834,915
Income (loss) from continuing operations before taxes	$ (9,802)	$(26,412)	$ 23,810	$ (12,404)
December 31, 2008				
Long-lived assets	$1,477,336	$ 47,170	$ 23,470	$1,547,976

(b) The segment operating results provided above represent amounts for continuing operations as presented on the accompanying statements of operations. Long-lived assets presented above represent amounts associated with all operations as of the periods then ended as indicated. Revenues from external customers are assigned to geographic region based upon the domicile of the subsidiary providing the services or products to the customers.

16. Legal matters and contingencies:

In the normal course of our business, we are a party to various pending or threatened claims, lawsuits and administrative proceedings seeking damages or other remedies concerning our commercial operations, products, employees and other matters, including warranty and product liability claims and occasional claims by individuals alleging exposure to hazardous materials, on the job injuries and fatalities as a result of our products or operations. Many of the claims filed against us relate to motor vehicle accidents which can result in the loss of life or serious bodily injury. Some of these claims relate to matters occurring prior to our acquisition of businesses. In certain cases, we are entitled to indemnification from the sellers of such businesses.

Although we cannot know or predict with certainty the outcome of any claim or proceeding or the effect such outcomes may have on us, we believe that any liability resulting from the resolution of any of these matters, to the extent not otherwise provided for or covered by insurance, will not have a material adverse effect on our financial position, results of operations or liquidity.

We have historically incurred additional insurance premium related to a cost-sharing provision of our general liability insurance policy, and we cannot be certain that we will not incur additional costs until either existing claims become further developed or until the limitation periods expire for each respective policy year. Any such additional premiums should not have a material adverse effect on our financial position, results of operations or liquidity. We incurred no additional premium related to this cost-sharing provision of our general liability policy for the years ended December 31, 2010, 2009 or 2008.

17. Financial instruments:

(a) Interest rate risk:

We currently have little exposure to interest rate risks. At December 31, 2010, 100% of our outstanding debt related to the senior notes issued in December 2006 with a fixed interest rate of 8%. We are exposed to variable interest rate impact related to our outstanding letters of credit under our amended credit facility, See Note 11, "Long-term debt."

(b) Foreign currency rate risk:

We are exposed to foreign currency fluctuations in relation to our foreign operations. Approximately 5% of our revenues from continuing operations were derived from operations conducted in Canadian dollars for the years ended December 31, 2010 and 2009. For our Canadian operations, we recorded net income from continuing operations before taxes of $1,255 for the year ended December 31, 2010 and a net loss from continuing operations before taxes of $11,069 for the year ended December 31, 2009. Total assets denominated in Canadian dollars at December 31, 2010 and 2009 were $71,842 and $59,343, respectively.

(c) Credit risk:

A significant portion of our trade accounts receivable are from companies in the oil and gas industry, and as such, we are exposed to normal industry credit risks. We evaluate the credit-worthiness of our major new and existing customers' financial condition and generally do not require collateral.

For the year ended December 31, 2010, we had two customers who provided 12.2% and 10.7% of our total annual revenue. For the year ended December 31, 2009, the same two customers represented 9.9% and 9.7% of our revenue. We did not have revenues from any single customer which amounted to 10% or more of our total annual revenue for the year ended December 31, 2008.

18. Commitments and contingences:

We have non-cancelable operating lease commitments for equipment and office space. These commitments for the next five years and thereafter are as follows at December 31, 2010:

2011	$27,287
2012	21,624
2013	17,538
2014	10,487
2015	4,954
Thereafter	11,055
	$92,945

We expensed operating lease payments totaling $31,595, $25,477 and $22,750 for the years ended December 31, 2010, 2009 and 2008, respectively.

19. Related party transactions:

We believe all transactions with related parties have terms and conditions no less favorable to us than transactions with unaffiliated parties.

We have entered into lease agreements for properties owned by certain of our employees and former officers. The leases expire at different times through December 2016. Total lease expense pursuant to these leases was $2,993, $2,749 and $2,828 for the years ended December 31, 2010, 2009 and 2008, respectively.

In connection with the Complete Energy Services, Inc. ("CES") acquisition of Hamm Co. in 2004, CES entered into a certain Strategic Customer Relationship Agreement with Continental Resources, Inc. ("CRI"). By virtue of the Combination, through a subsidiary, we are now party to such agreement. The agreement provides CRI the option to engage a limited amount of our assets into a long-term contract at market rates. Mr. Hamm is a majority owner of CRI and serves as a member of our board of directors.

We provided services to companies that were majority-owned by certain of our directors during 2010 which totaled $131,524, of which $131,337 was sold to CRI and $187 was sold to other companies. In 2009, these sales totaled $40,623, of which $40,343 was sold to CRI, and $280 was sold to other companies and in 2008, these sales totaled $61,194, of which $60,634 was sold to CRI, and $560 was sold to other companies. We also purchased services from companies that are majority-owned by certain of our directors which totaled $556 in 2010, of which $490 was purchased from CRI and $66 was purchased from other companies. These purchases for 2009 totaled $1,423, of which $1,191 was purchased from CRI and $232 was purchased from other companies and in 2008, these purchases totaled $2,866, of which $2,750 was purchased from CRI and $116 was purchased from other companies. At December 31, 2010 and 2009, our trade receivables included amounts from CRI of $50,048 and $5,957, respectively, with no balance in trade payables for either of these periods.

We provided services to companies majority-owned by certain of our officers, or current or former officers of our subsidiaries, for the years ended December 31, 2010, 2009 and 2008. In 2010, these sales totaled $4,065, of which $2,537 was sold to HEP Oil ("HEP"), $21 was sold to Peak Oilfield and $1,507 was sold to other companies. For 2009, these sales totaled $3,552, of which $2,433 was sold to HEP, $9 was sold to Peak Oilfield and $1,110 was sold to other companies. For 2008, these sales totaled $11,256, of which $3,348 was sold to HEP, $1,660 was sold to Cimarron, $3,513 was sold to Peak Oilfield and $2,735 was sold to other companies. HEP, Cimarron and Peak Oilfield are owned by a former officer of one of our subsidiaries who resigned his position in late 2006 but continued to provide consulting services through early 2007. We also purchased services from companies majority-owned by certain officers, or current or former officers of one of our subsidiaries. For 2010, these purchases totaled $180,119, of which $56,994 was purchased from Resource Transport, $40,245 was purchased from Texas Specialty Sands, LLC primarily for the purchase of sand used for pressure pumping activities, $31,552 was purchased from Ortowski Construction primarily related to the manufacture of pressure pumping units, $30,217 was purchased from ORTEQ Energy Services, a heavy equipment construction company which also manufactures pressure pumping equipment, $7,772 was purchased from ProFuel, $7,935 was purchased from Wood Flowline Products, LLC $43 was purchased from Select Energy Services LLC and affiliates and $5,361 was purchased from other companies. For 2009, these purchases totaled $40,373, of which $13,920 was purchased from Ortowski Construction, $12,005 was purchased from Texas Specialty Sands, LLC, $3,302 was purchased from Resource Transport, $2,642 was purchased from ProFuel, $3,535 was purchased from Wood Flowline Products, LLC, $24 was purchased from Select Energy Services LLC and affiliates and $4,945 was purchased from other companies. For 2008, these purchases totaled $61,708, of which $25,344 was purchased from Ortowski Construction, $7,910 was purchased from Texas Specialty Sands, LLC, $4,809 was purchased from Resource Transport, $5,601 was purchased from ProFuel, $16,595 was purchased from Select Energy Services LLC and affiliates and $1,449 was purchased from other companies. Ortowski Construction, ORTEQ Energy Services, Texas Specialty Sands, LLC, Resource Transport, Pro Fuel and Wood Flowline Products, LLC are owned by parties, one of whom is a former employee, who are related to a current officer of a subsidiary, or the officer himself. Select Energy Services LLC is owned by a former officer of one of our subsidiaries who purchased a disposal group from us during May 2008. Of the total purchases from Select Energy Services, LLC, $11,098 was purchased from the businesses sold as part of this disposal group for the period May 19, 2008 through December 31, 2008. At December 31, 2010 and 2009, our trade receivables included amounts from HEP of $310 and $270, respectively.

One of our Mexican subsidiaries, Servicios Petrotec de S.A. de C.V., has purchased services from entities in which certain of our current and former employees have ownership interests. We purchased fluid transportation, industrial cleaning, pumping equipment and safety equipment, totaling $1,575, $1,262 and $1,485 for the years ended December 31, 2010, 2009 and 2008, respectively.

We provided services totaling $1,430, $1,012 and $1,697 for the years ended December 31, 2010, 2009 and 2008, respectively, to Laramie Energy LLC and Laramie Energy II (collectively "Laramie"), companies for which one of our directors serves as an officer. At December 31, 2010 and 2009, our trade receivables included amounts due from Laramie totaling $858 and $326, respectively.

For the years ended December 31, 2010, 2009 and 2008, we provided services totaling $8,555, $3,613 and $9,468, respectively, and purchased services totaling $3,456, $8,784 and $14,108, respectively, from companies, or their affiliates, that formerly employed our current officers or for customers on whose board of directors or management team certain of our current directors serve.

We paid $3,450 in May 2009 pursuant to subordinated note agreements with certain employees, including former officers of subsidiaries, related to promissory notes issued in conjunction with 2005 and 2004 business acquisitions.

Premier Integrated Technologies Ltd. ("PIT"), an affiliate of IPS, purchased $3,823, $2,427 and $1,493 of machining services from a company controlled by employees of PIT during the years ended December 31, 2010, 2009 and 2008, respectively.

On May 19, 2008, we sold certain business assets located primarily in north Texas which included our product supply stores, certain drilling logistics assets and other completion and production services assets to Select Energy Services, L.L.C., an oilfield service company located in Gainesville, Texas which is partially owned by Mr. Schmitz who resigned as an officer of one of our subsidiaries in late 2006. The proceeds from the sale totaled $50,150 in cash and we received assets with a fair market value of $7,987. We recorded a loss of $6,935 associated with the sale of this disposal group, and we will provide certain administrative functions for a period of one year at an agreed-upon rate. For the period May 20, 2008 through December 31, 2008, we sold services totaling $1,509 and purchased products and services totaling $11,098 from these former subsidiaries. See Note 14, "Discontinued operations." At December 31, 2010, our trade receivables and payables included amounts related to these disposed businesses which totaled $7 and $177, respectively and at December 31, 2009, our trade receivables and payables included amounts related to these disposed businesses which totaled $21 and $295, respectively.

20. Retirement plans:

Effective January 1, 2009, we adopted and established (and subsequently amended and restated for compliance and other issues) the Complete Production Services, Inc. Deferred Compensation Plan, whereby eligible participants, including members of senior management, non-employee directors and certain highly-compensated individuals, could defer up to 90% of their compensation and up to 90% of the employees' annual incentive bonus, or 100% of director compensation for services rendered, into various investment options pre-tax. For amounts deferred, we will match the contribution dollar-for-dollar up to four percent of compensation minus $3.3, and we may make other discretionary contributions pursuant to resolutions of this plan's administrative committee. Participants immediately vest in amounts deferred as well as any matching or discretionary contributions we make. Participants bear the risk of loss associated with investment gains or losses. We intend that this plan will meet all the requirements necessary to be a nonqualified, unfunded, unsecured plan of deferred compensation within the meaning of Sections 201(2), 301(a)(3) and 401(a)(1) of the Employee Retirement Income Security Act of 1974, as amended. We have recorded an asset and corresponding liability totaling $882 related to the rabbi trust associated with our deferred compensation plan. For the years ended December 31, 2010 and 2009, we expensed an insignificant amount related to matching contributions associated with this deferred compensation plan.

We maintain defined contribution retirement plans for substantially all of our U.S. and Canadian employees who have completed six months of service. Employees may voluntarily contribute up to a maximum percentage of their salaries to these plans subject to certain statutory maximum dollar values. The employer contributions vest immediately with respect to the Canadian RRSP plan and U.S. 401(k) plan. In response to market conditions, effective May 1, 2009, we amended our 401(k) plan and deferred compensation plan to suspend matching contributions to such plans through December 31, 2010. We re-instated our matching contribution in 2011, see Note 24, "Subsequent events."

We expensed $436, $2,231 and $6,101 related to our various defined contribution plans for the years ended December 31, 2010, 2009 and 2008, respectively.

We provide a seniority premium benefit to substantially all of our Mexican employees, through a subsidiary, in accordance with Mexican law. The benefit consists of a one-time payment equivalent to 12-days wages for each year of service (calculated at the employee's current wage rate but not exceeding twice the minimum wage), payable upon voluntary termination after fifteen years of service, involuntary termination or death. In addition, we provide statutory mandated severance benefits to substantially all Mexican employees, which includes a one-time payment of three months wages, plus 20-days wages for each year of service, payable upon involuntary termination without cause and charged to income as incurred. We accrued $1,249 and $1,604 at December 31, 2010 and 2009, respectively, related to our liability under this benefit arrangement in Mexico.

21. Unaudited selected quarterly data:

The following table presents selected quarterly financial data for the years ended December 31, 2010 and 2009 (unaudited, in thousands, except per share amounts):

	2010 — Quarter Ended			
	March 31,	**June 30,**	**September 30,**	**December 31,**
Revenues	$309,704	$360,245	$418,609	$472,835
Operating income	$ 10,589	$ 39,869	$ 68,181	$ 74,446
Net income (loss)	$ (2,762)	$ 15,671	$ 33,030	$ 38,219
Earnings (loss) per share(a):				
Basic	$ (0.04)	$ 0.21	$ 0.43	$ 0.50
Diluted	$ (0.04)	$ 0.20	$ 0.42	$ 0.49

	2009 — Quarter Ended			
	March 31,	**June 30,**	**September 30,**	**December 31,**
Revenues	$336,681	$238,398	$229,913	$ 251,402
Operating income (loss)	$ 14,006	$ (22,902)	$ (64,132)	$(114,384)
Net loss	$ (336)	$ (25,832)	$ (52,025)	$(103,475)
Loss per share(a):				
Basic	$ 0.00	$ (0.34)	$ (0.69)	$ (1.38)
Diluted	$ 0.00	$ (0.34)	$ (0.69)	$ (1.38)

(a) Quarterly earnings per share amounts were calculated based upon the weighted average number of shares outstanding for the applicable quarter. Therefore the sum of the quarterly earnings per share results may not agree to earnings per share for the year in the accompanying Statements of Operations, as the annual results were calculated based upon the weighted average number of shares outstanding for the year.

22. Guarantor and non-guarantor condensed consolidating financial statements:

The following tables present the financial data required by SEC Regulation S-X Rule 3-10(f) related to condensed consolidating financial statements, and includes the following: (1) condensed consolidating balance sheets for the years ended December 31, 2010 and 2009; (2) condensed consolidating statements of operations for the years ended December 31, 2010, 2009 and 2008; and (3) condensed consolidating statements of cash flows for the years ended December 31, 2010, 2009 and 2008.

Condensed Consolidating Balance Sheet
December 31, 2010

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Current assets					
Cash and cash equivalents	$ 111,834	$ 569	$ 31,046	$ (16,768)	$ 126,681
Accounts receivable, net	696	313,936	31,016	—	345,648
Inventory, net	—	21,935	11,601	—	33,536
Prepaid expenses	6,388	10,980	1,332	—	18,700
Income tax receivable	10,164	13,298	—	—	23,462
Current deferred tax assets	2,499	—	—	—	2,499
Other current assets	882	502	—	—	1,384
Total current assets	132,463	361,220	74,995	(16,768)	551,910
Property, plant and equipment, net	4,730	898,013	53,285	—	956,028
Investment in consolidated subsidiaries	930,631	115,449	—	(1,046,080)	—
Inter-company receivable	554,482	—	445	(554,927)	—
Goodwill	15,531	232,144	2,858	—	250,533
Other long-term assets, net	29,966	10,161	1,978	—	42,105
Total assets	$1,667,803	$1,616,987	$133,561	$(1,617,775)	$1,800,576
Current liabilities					
Accounts payable	$ 376	$ 82,952	$ 8,539	$ (16,768)	$ 75,099
Accrued liabilities	18,269	21,355	4,667	—	44,291
Accrued payroll and payroll burdens	4,353	19,325	2,890	—	26,568
Accrued interest	2,439	1	6	—	2,446
Income taxes payable	(1,043)	—	1,043	—	—
Total current liabilities	24,394	123,633	17,145	(16,768)	148,404
Long-term debt	650,000	—	—	—	650,000
Inter-company payable	—	553,907	1,020	(554,927)	—
Deferred income taxes	186,693	3,794	(65)	—	190,422
Other long-term liabilities	882	5,022	12	—	5,916
Total liabilities	861,969	686,356	18,112	(571,695)	994,742
Stockholders' equity					
Total stockholders' equity	805,834	930,631	115,449	(1,046,080)	805,834
Total liabilities and stockholders' equity	$1,667,803	$1,616,987	$133,561	$(1,617,775)	$1,800,576

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements — (Continued)

Condensed Consolidating Balance Sheet
December 31, 2009

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Current assets					
Cash and cash equivalents	$ 64,871	$ 519	$ 17,001	$ (5,031)	$ 77,360
Accounts receivable, net	610	143,135	27,539	—	171,284
Inventory, net	—	23,001	14,463	—	37,464
Prepaid expenses	3,897	13,052	994	—	17,943
Income tax receivable	35,404	20,201	2,001	—	57,606
Current deferred tax assets	8,158	—	—	—	8,158
Other current assets	—	111	—	—	111
Total current assets	112,940	200,019	61,998	(5,031)	369,926
Property, plant and equipment, net	4,222	876,304	60,607	—	941,133
Investment in consolidated subsidiaries	755,435	104,974	—	(860,409)	—
Inter-company receivable	607,325	—	—	(607,325)	—
Goodwill	15,531	225,434	2,858	—	243,823
Other long-term assets, net	16,026	13,803	4,143	—	33,972
Total assets	$1,511,479	$1,420,534	$129,606	$(1,472,765)	$1,588,854
Current liabilities					
Current maturities of long-term debt	$ —	$ 228	$ —	$ —	$ 228
Accounts payable	445	30,028	6,303	(5,031)	31,745
Accrued liabilities	14,064	18,257	8,781	—	41,102
Accrued payroll and payroll burdens	388	10,847	2,324	—	13,559
Accrued interest	3,198	—	8	—	3,206
Notes payable	1,068	1	—	—	1,069
Income taxes payable	—	—	813	—	813
Total current liabilities	19,163	59,361	18,229	(5,031)	91,722
Long-term debt	650,000	—	2	—	650,002
Inter-company payable	—	601,947	5,378	(607,325)	—
Deferred income taxes	143,427	3,793	1,020	—	148,240
Total liabilities	812,590	665,101	24,629	(612,356)	889,964
Stockholders' equity					
Total stockholders' equity	698,889	755,433	104,977	(860,409)	698,890
Total liabilities and stockholders' equity	$1,511,479	$1,420,534	$129,606	$(1,472,765)	$1,588,854

Condensed Consolidated Statement of Operations
Year Ended December 31, 2010

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Revenue:					
Service	$ —	$1,401,665	$132,774	$ (6,821)	$1,527,618
Product	—	3,247	30,528	—	33,775
	—	1,404,912	163,302	(6,821)	1,561,393
Service expenses	—	889,862	102,052	(6,821)	985,093
Product expenses	—	3,452	22,495	—	25,947
Selling, general and administrative expenses	39,090	122,189	14,166	—	175,445
Depreciation and amortization	1,354	168,104	12,365	—	181,823
Income (loss) before interest and taxes	(40,444)	221,305	12,224	—	193,085
Interest expense	58,132	5,653	105	(6,221)	57,669
Interest income	(6,511)	(8)	(24)	6,221	(322)
Equity in earnings of consolidated affiliates	(140,929)	(8,926)	—	149,855	—
Income (loss) before taxes	48,864	224,586	12,143	(149,855)	135,738
Taxes	(35,294)	83,657	3,217	—	51,580
Net income (loss)	$ 84,158	$ 140,929	$ 8,926	$(149,855)	$ 84,158

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements — (Continued)

Condensed Consolidated Statement of Operations
Year Ended December 31, 2009

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Revenue:					
Service	$ —	$ 902,157	$115,768	$ (5,612)	$1,012,313
Product	—	13,752	30,329	—	44,081
	—	915,909	146,097	(5,612)	1,056,394
Service expenses	—	613,823	83,953	(5,612)	692,164
Product expenses	—	13,273	19,928	—	33,201
Selling, general and administrative expenses	33,785	129,240	18,395	—	181,420
Depreciation and amortization	1,602	185,601	13,529	—	200,732
Fixed asset and other intangibles impairment loss	—	38,646	—	—	38,646
Goodwill impairment loss	—	97,643	—	—	97,643
Income (loss) before interest and taxes	(35,387)	(162,317)	10,292	—	(187,412)
Interest expense	56,955	6,713	177	(6,950)	56,895
Interest income	(7,010)	(6)	(13)	6,950	(79)
Write-off of deferred financing costs	528	—	—	—	528
Equity in earnings of consolidated affiliates	133,340	(8,846)	—	(124,494)	—
Income (loss) before taxes	(219,200)	(160,178)	10,128	124,494	(244,756)
Taxes	(37,532)	(26,838)	1,282	—	(63,088)
Net income (loss)	$(181,668)	$(133,340)	$ 8,846	$ 124,494	$ (181,668)

Condensed Consolidated Statement of Operations
Year Ended December 31, 2008

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Revenue:					
Service	$ —	$1,637,755	$142,625	$ (4,567)	$1,775,813
Product	—	13,988	45,114	—	59,102
	—	1,651,743	187,739	(4,567)	1,834,915
Service expenses	—	997,184	101,957	(4,567)	1,094,574
Product expenses	—	11,507	30,407	—	41,914
Selling, general and administrative expenses	38,293	142,615	17,292	—	198,200
Depreciation and amortization	1,516	165,065	14,616	—	181,197
Impairment charge	27,670	218,500	25,836	—	272,006
Income (loss) from continuing operations before interest and taxes	(67,479)	116,872	(2,369)	—	47,024
Interest expense	62,247	10,939	634	(14,091)	59,729
Interest income	(14,245)	(13)	(134)	14,091	(301)
Equity in earnings of consolidated affiliates	10,431	8,111	—	(18,542)	—
Income (loss) from continuing operations before taxes	(125,912)	97,835	(2,869)	18,542	(12,404)
Taxes	(40,457)	107,520	5,242	—	72,305
Income (loss) from continuing operations	(85,455)	(9,685)	(8,111)	18,542	(84,709)
Discontinued operations (net of tax)	—	(4,859)	—	—	(4,859)
Net income (loss)	$ (85,455)	$ (14,544)	$ (8,111)	$ 18,542	$ (89,568)

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements — (Continued)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2010

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Cash provided by:					
Net income (loss)	$ 84,158	$ 140,929	$ 8,926	$(149,855)	$ 84,158
Items not affecting cash:					
Equity in loss of consolidated affiliates	(140,929)	(8,926)	—	149,855	—
Depreciation and amortization	1,354	168,104	12,365	—	181,823
Other	15,066	50,422	(632)	—	64,856
Changes in operating assets and liabilities, net of effect of acquisitions	30,112	(134,999)	1,500	(11,292)	(114,679)
Net cash provided by (used in) operating activities	(10,239)	215,530	22,159	(11,292)	216,158
Investing activities:					
Additions to property, plant and equipment	(1,862)	(138,808)	(4,353)	—	(145,023)
Inter-company receipts	52,843	—	—	(52,843)	—
Business acquisitions, net of cash acquired	—	(33,721)	—	—	(33,721)
Proceeds from sale of fixed assets	—	5,317	165	—	5,482
Other	(826)	—	—	—	(826)
Net cash provided by (used for) investing activities	50,155	(167,212)	(4,188)	(52,843)	(174,088)
Financing activities:					
Repayments of long-term debt	—	(228)	(2)	—	(230)
Repayments of notes payable	(1,069)	—	—	—	(1,069)
Inter-company borrowings (repayments)	—	(48,040)	(4,358)	52,398	—
Proceeds from issuances of common stock	8,082	—	—	—	8,082
Treasury stock purchased	(1,431)	—	—	—	(1,431)
Other	1,465	—	—	—	1,465
Net cash provided by (used in) financing activities	7,047	(48,268)	(4,360)	52,398	6,817
Effect of exchange rate changes on cash	—	—	434	—	434
Change in cash and cash equivalents	46,963	50	14,045	(11,737)	49,321
Cash and cash equivalents, beginning of period	64,871	519	17,001	(5,031)	77,360
Cash and cash equivalents, end of period	$ 111,834	$ 569	$31,046	$ (16,768)	$ 126,681

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements — (Continued)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2009

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Cash provided by:					
Net income (loss)	$(181,668)	$(133,340)	$ 8,846	$ 124,494	$(181,668)
Items not affecting cash:					
Equity in loss of consolidated affiliates	133,340	(8,846)	—	(124,494)	—
Depreciation and amortization	1,602	185,601	13,529	—	200,732
Fixed asset and other intangibles impairment loss	—	38,646	—	—	38,646
Goodwill impairment loss	—	97,643	—	—	97,643
Other	14,603	14,658	3,697	—	32,958
Changes in operating assets and liabilities	96,585	1,758	(8,742)	7,292	96,893
Net cash provided by operating activities	64,462	196,120	17,330	7,292	285,204
Investing activities:					
Additions to property, plant and equipment	(649)	(32,431)	(4,351)	—	(37,431)
Inter-company receipts	172,228	(502)	—	(171,726)	—
Proceeds from sale of fixed assets	—	19,996	804	—	20,800
Other	—	(1,497)	—	—	(1,497)
Net cash provided by (used for) investing activities	171,579	(14,434)	(3,547)	(171,726)	(18,128)
Financing activities:					
Issuances of long-term debt	1,635	—	1,559	—	3,194
Repayments of long-term debt	(187,628)	(3,907)	(9,074)	—	(200,609)
Repayments of notes payable	(8,244)	—	—	—	(8,244)
Inter-company borrowings (repayments)	—	(177,606)	5,880	171,726	—
Proceeds from issuances of common stock	496	—	—	—	496
Treasury stock purchased	(132)	—	—	—	(132)
Deferred financing fees	(2,911)	—	—	—	(2,911)
Other	215	—	—	—	215
Net cash provided by (used in) financing activities	(196,569)	(181,513)	(1,635)	171,726	(207,991)
Effect of exchange rate changes on cash	—	—	(225)	—	(225)
Change in cash and cash equivalents	39,472	173	11,923	7,292	58,860
Cash and cash equivalents, beginning of period	25,399	346	5,078	(12,323)	18,500
Cash and cash equivalents, end of period	$ 64,871	$ 519	$17,001	$ (5,031)	$ 77,360

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2008

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Cash provided by:					
Net income (loss)	$ (89,568)	$ (14,544)	$ (8,111)	$ 22,655	$ (89,568)
Items not affecting cash:					
Equity in loss of consolidated affiliates	14,544	8,111	—	(22,655)	—
Depreciation and amortization	1,516	167,059	14,616	—	183,191
Impairment charge	27,670	218,500	25,836	—	272,006
Other	5,182	35,204	680	—	41,066
Changes in operating assets and liabilities, net of effect of acquisitions	(61,520)	18,953	(8,143)	(5,576)	(56,286)
Net cash provided by (used in) operating activities	(102,176)	433,283	24,878	(5,576)	350,409
Investing activities:					
Business acquisitions, net of cash acquired	—	(180,154)	—	—	(180,154)
Additions to property, plant and equipment	(1,632)	(229,307)	(22,837)	—	(253,776)
Inter-company receipts	87,395	—	—	(87,395)	—
Proceeds from sale of disposal group	—	50,150	—	—	50,150
Other	—	9,369	313	—	9,682
Net cash provided by (used for) investing activities	85,763	(349,942)	(22,524)	(87,395)	(374,098)
Financing activities:					
Issuances of long-term debt	341,043	—	9,072	—	350,115
Repayments of long-term debt	(314,605)	(814)	(13,863)	—	(329,282)
Repayments of notes payable	(14,001)	—	—	—	(14,001)
Inter-company borrowings (repayments)	—	(87,140)	(255)	87,395	—
Proceeds from issuances of common stock	12,014	—	—	—	12,014
Other	9,144	—	—	—	9,144
Net cash provided by (used in) financing activities	33,595	(87,954)	(5,046)	87,395	27,990
Effect of exchange rate changes on cash	—	—	1,165	—	1,165
Change in cash and cash equivalents	17,182	(4,613)	(1,527)	(5,576)	5,466
Cash and cash equivalents, beginning of period	8,217	4,959	6,605	(6,747)	13,034
Cash and cash equivalents, end of period	$ 25,399	$ 346	$ 5,078	$(12,323)	$ 18,500

23. Recent accounting pronouncements and authoritative literature:

The FASB has addressed the issue of business combinations during recent years. In December 2007, the FASB issued guidance regarding business combinations that substantially replaced previously existing guidance, while maintaining the precepts prescribed therein, and further requiring that all assets and liabilities and non-controlling interests of an acquired business be measured at their fair value, with limited exceptions, including the recognition of acquisition-related costs and anticipated restructuring costs separate from the acquired net assets. In addition, entities must recognize pre-acquisition contingencies, as well as assets and liabilities assumed arising from contractual contingencies as of the acquisition date, measured at acquisition-date fair values, and must recognize all other contractual contingencies as of the acquisition date, measured at their acquisition-date fair values only if it is more likely than not that these contingencies meet the definition of an asset or liability. In addition, this standard provides guidance for measuring goodwill and recording a bargain purchase, defined as a business combination in which total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any non-controlling interest in the acquiree, and states that the acquiring entity must recognize that excess in earnings as a gain attributable to the acquirer. The FASB amended this guidance in April 2009 as it relates to accounting for assets and liabilities assumed in a business combination which arise from contingencies. This amendment requires that contingent assets acquired and liabilities assumed in a business combination to be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the measurement period. If fair value cannot be reasonably estimated during the measurement period, the contingent asset or liability would be recognized as a contingency, in accordance with existing U.S. GAAP, with reasonable estimation of the amount of loss, if any. This amendment also eliminated the specific subsequent accounting guidance for contingent assets and liabilities, without significantly revising the original guidance. However, contingent consideration arrangements of an acquiree assumed by the acquirer in a business combination would still be initially and subsequently measured at fair value. We originally adopted the revised guidance for business combinations when it became effective on January 1, 2009, and the amendment thereto, subsequently in 2009. In December 2010, the FASB updated this guidance to require each public entity that presents comparative financial statements to disclose the revenue and earnings of the combined entity as if the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. In addition, this amendment expands the supplemental pro forma disclosures related to such a business combination to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. This most recent amendment should be accounted for prospectively for business combinations for which the acquisition date is on or after January 1, 2011, for calendar-year reporting entities. Early adoption is permitted. Although we did not early adopt this standard, we do not expect this guidance to have a material impact on our financial position, results of operations or cash flows. We will comply with this update for business combinations that have a material impact on our financial results.

In May 2009, the FASB issued a standard regarding subsequent events that provides guidance as to when an entity should recognize events or transactions occurring after a balance sheet date in its financial statements and the necessary disclosures related to these events. Specifically, the entity should recognize subsequent events that provide evidence about conditions that existed at the balance sheet date, including significant estimates used to prepare financial statements. Originally, this standard required entities to disclose the date through which subsequent events had been evaluated and whether that date was the date the financial statements were issued or the date the financial statements were available to be issued. We adopted this accounting standard effective June 30, 2009 and applied its provisions prospectively. In February 2010, the FASB modified this standard to eliminate the requirement for publicly-traded entities to disclose the date through which subsequent events have been evaluated.

In January 2010, the FASB issued "Fair Value Measurements and Disclosure (Topic 820)" which clarified the disclosure requirements of existing U.S. GAAP related to fair value measurements. This standard requires additional disclosures about recurring and non-recurring fair value measurements as follows: (1) for transfers in and out of Level 1 and Level 2 fair value measurements, as those terms are currently defined in existing authoritative literature, a reporting entity is required to disclose the amount of the movement between levels and an explanation for the movement; (2) for activity at Level 3, primarily fair value measurements based on unobservable inputs, a reporting entity is required to present separately information about purchases, sales, issuances and settlements, as opposed to presenting such transactions on a net basis; (3) in the event of a disaggregation, a reporting entity is required to provide fair value measurement disclosure for each class of assets and liabilities; and (4) a reporting entity is required to provide disclosures about the valuation techniques and inputs used to measure fair value for both recurring and non-recurring fair value measurements for items that fall in either Level 2 or Level 3. These disclosure requirements are effective for interim and annual reporting periods beginning after December 15, 2009, except for disclosures about purchases, sales, issuances and settlements in the roll forward of activity in Level 3 fair value measurements for which disclosure becomes effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years.

On March 30, 2010, the President of the United States signed the Health Care and Education Reconciliation Act of 2010, which is a reconciliation bill that amends the Patient Protection and Affordable Care Act that was signed by the President on March 23, 2010. Certain provisions of this law became effective during 2010. We have reviewed our health insurance plan provisions with third-party consultants and continue to evaluate our position relative to the changes in the law. We do not believe that the provisions which have taken effect will have a significant impact on the operation of our existing health insurance plan. However, future provisions under the law which become effective in subsequent periods may impact our health insurance plan and our overall financial position. We are evaluating these provisions as they become effective and continue to seek guidance from the FASB and SEC related to the implications of this new legislation on accounting and disclosure requirements. We expect that this legislation will have an impact on our financial position, results of operations and cash flows, but we cannot determine the extent of the impact at this time.

In December 2010, the FASB issued additional guidance related to accounting for intangible assets and goodwill. The amendments in this update modify Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist. The qualitative factors are consistent with the existing guidance and examples, which require that goodwill of a reporting unit be tested for impairment between annual test dates if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. This update is effective for public entities with fiscal years beginning after December 15, 2010 and interim periods within those years. Early adoption is not permitted. We are currently evaluating the effect this proposed guidance may have on our financial position, results of operations and cash flows.

24. Subsequent events:

On January 31, 2011, the Compensation Committee of our Board of Directors approved the annual grant of stock options and non-vested restricted stock to certain employees, officers and directors. Pursuant to this authorization, we issued 428,860 shares of non-vested restricted stock at a grant price of $27.94. We expect to recognize compensation expense associated with this grant of non-vested restricted stock totaling $11,982 ratably over the three-year vesting period. In addition, we granted 213,200 stock options to purchase shares of our common stock at an exercise price of $27.94. These stock options vest ratably over a three-year period. We will recognize compensation expense associated with these stock option grants over the vesting period.

Pursuant to our 2008 Incentive Award Plan, holders of unvested restricted stock have the option to authorize us to repurchase shares equivalent to the cost of the withholding tax associated with the vesting of restricted stock and to remit the withholding taxes on behalf of the holder. Pursuant to this provision, we purchased 64,348 shares of our common stock on January 29, 2011 for $27.29 per share, 91,417 shares on January 30, 2011 for $27.29 per share and 43,869 shares on January 31, 2011 for $27.94 per share. These shares were included in treasury stock at cost.

Effective January 1, 2011, we reinstated the matching contributions for our defined contribution retirement plans to provide for 100% matching of contributions, up to 4% of the employee's salary, depending on the plan. For a description of our retirement plans, see Note 20, "Retirement plans."

During the review of our property, plant and equipment at December 31, 2010 in conjunction with our annual impairment testing of long-term assets, we noted approximately $5,814 of salvage value assigned to various coiled tubing and wireline assets at one of our operating divisions. Although we evaluated these assets and the assets of the overall reporting unit for recoverability and noted no significant impairment based on an undiscounted cash flow projection, we believe that the salvage value assigned to these assets is no longer appropriate. These assets were acquired several years ago, and we believe the estimate for salvage value used at that time was appropriate. However, increasingly, our business is focusing on larger-diameter coiled tubing units and more technologically-advanced equipment. As such, we have changed our estimate of salvage value to zero and expect to depreciate these assets over their remaining useful lives, an average of 1.3 years at December 31, 2010. This change in estimate will be applied prospectively and is expected to increase our depreciation expense over the next five years as follows: 2011 — $4,867; 2012 — $789; 2013 — $134 and 2014 — $24.

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

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K.

Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures.

Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2010, the end of the period covered by this Annual Report on Form 10-K, our disclosure controls and procedures were effective at a reasonable assurance level to ensure that information required to be disclosed in the reports we file and submit under the Exchange Act is recorded, processed, summarized and reported as and when required.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a — 15(f) and 15d — 15(f) under the Exchange Act). Our internal control over financial reporting is a process designed by management, under the supervision of the Chief Executive Officer and Chief Financial Officer, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America, and includes those policies and procedures that:

(i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States, and that our receipts and expenditures are being made only in accordance with authorizations of management and our directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our consolidated financial statements.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improver override. Because of its inherent limitations, there is a risk that internal control over financial reporting may not prevent or detect, on a timely basis, material 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 and procedures may deteriorate. Accordingly, even effective internal control over financial reporting can only provide reasonable assurance of achieving their control objectives.

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria set forth by the committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.*

Based on our evaluation under the framework in *Internal Control — Integrated Framework,* our management concluded that, our internal control over financial reporting was effective as of December 31, 2010.

Grant Thornton LLP, the independent registered accounting firm who audited the consolidated financial statements included in this Annual Report, has issued a report on our internal control over financial reporting dated February 18, 2011, also included in this Annual Report and expressed an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2010.

Changes in Internal Control over Financial Reporting

As of December 31, 2010, there were no changes in our system of internal control over financial reporting (as defined in Rules 13a — 15(f) and 15d — 15(f) under the Exchange Act) that occurred during the last fiscal quarter then ended that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

In 2010, our management approved a plan to implement new accounting software which will replace our existing accounting systems at several of our operating divisions in a phased approach. Two divisions converted during the fourth quarter of 2010 and two divisions will convert during 2011. In addition, we implemented a new chart of accounts which is being adopted as these divisions convert to the new software. Although we believe the new software, once implemented, will enhance our internal controls over financial reporting and we believe that we have taken the necessary steps to maintain appropriate internal control over financial reporting during this period of system change, we will continuously monitor controls through and around the system to provide reasonable assurance that controls are effective during and after each step of this implementation process.

/s/ Joseph C. Winkler

Joseph C. Winkler
Chairman and Chief Executive Officer
February 18, 2011

/s/ Jose A. Bayardo

Jose A. Bayardo
Sr. Vice President and Chief Financial Officer
February 18, 2011

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

The information to be included in the sections entitled, "Election of Directors" and "Executive Officers," respectively, in the Definitive Proxy Statement of the Annual Meeting of Stockholders to be filed by us with the

Securities and Exchange Commission no later than 120 days after December 31, 2010 (the "2010 Proxy Statement") is incorporated herein by reference.

The information to be included in the section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" in the 2011 Proxy Statement is incorporated herein by reference.

The information to be included in the section entitled "Corporate Governance" in the 2011 Proxy Statement is incorporated herein by reference.

We have filed, as exhibits to this Annual Report on Form 10-K, the certifications of our Principal Executive Officer and Principal Financial Officer required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Item 11. *Executive Compensation.*

The information to be included in the sections entitled "Executive Compensation" and "Directors' Compensation" in the 2011 Proxy Statement is incorporated herein by reference.

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

The information to be included in the section entitled "Security Ownership of Certain Beneficial Owners and Management" in the 2011 Proxy Statement is incorporated herein by reference.

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

The information to be included in the sections entitled "Certain Relationships and Related Transactions" and "Board Independence" in the 2011 Proxy Statement is incorporated herein by reference.

Item 14. *Principal Accounting Fees and Services.*

The information to be included in the section entitled "Independent Registered Public Accountants" in the 2011 Proxy Statement is incorporated herein by reference.

PART IV

Item 15. *Exhibits, Financial Statement Schedules.*

(a) *List the following documents filed as a part of the report:*

(b) *Exhibits* Please see our Exhibit Index, on Page 117.

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

COMPLETE PRODUCTION SERVICES, INC.

By: /s/ *JOSEPH C. WINKLER*

Name: Joseph C. Winkler
Title: Chief Executive Officer

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Joseph C. Winkler and Jose A. Bayardo, and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and re-substitution, to execute in his name, place and stead, in any and all capacities, any or all amendments to this Annual Report on Form 10-K, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents and each of them, full power and authority to do and perform in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

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	Position	Date
/s/ *JOSEPH C. WINKLER* Joseph C. Winkler	Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 18, 2011
/s/ *JOSE A. BAYARDO* Jose A. Bayardo	Sr. Vice President and Chief Financial Officer (Principal Financial Officer)	February 18, 2011
/s/ *DEWAYNE WILLIAMS* Dewayne Williams	Vice President-Accounting and Controller (Principal Accounting Officer)	February 18, 2011
/s/ *ROBERT BOSWELL* Robert Boswell	Director	February 18, 2011
/s/ *HAROLD G. HAMM* Harold G. Hamm	Director	February 18, 2011
/s/ *MIKE MCSHANE* Mike McShane	Director	February 18, 2011
/s/ *W. MATT RALLS* W. Matt Ralls	Director	February 18, 2011
/s/ *MARCUS WATTS* Marcus Watts	Director	February 18, 2011
/s/ *JAMES D. WOODS* James D. Woods	Director	February 18, 2011

The following exhibits are incorporated by reference into the filing indicated or are filed herewith.

EXHIBIT INDEX

Exhibit No.		Exhibit Title	Incorporated by Reference to the Following
3.1	—	Amended and Restated Certificate of Incorporation	Form S-1/A, filed January 18, 2006, (file no. 333-128750)
3.2	—	Amended and Restated Bylaws	Form 8-K, filed February 27, 2008
4.1	—	Specimen Stock Certificate representing common stock	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
4.2	—	Indenture dated December 6, 2006, between Complete Production Services, Inc. and the Guarantors Named Therein, with Wells Fargo Bank, National Association, as Trustee, for 8% Senior Notes due 2016	Form 8-K, filed December 8, 2006
4.3	—	Registration Rights Agreement dated November 8, 2006 pursuant to Stock Purchase Agreement dated November 8, 2006 among Complete Production Services, Inc., Integrated Production Services, LLC and Pumpco Services Inc. and Each Seller Listed on Schedule I Thereto	Form 8-K, filed November 14, 2006
4.4	—	First Supplemental Indenture, dated August 28, 2007, among Complete Production Services, Inc., the subsidiary guarantors party thereto, and Wells Fargo Bank, National Association, as trustee	Form 10-Q, filed November 2, 2007, (file no. 001-32858)
10.1	—	Form of Indemnification Agreement	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.2*	—	Employment Agreement dated as of June 20, 2005 with Joseph C. Winkler	Form S-1, filed September 30, 2005, (file no. 333-128750)
10.3	—	Amended and Restated Stockholders' Agreement by and among Complete Production Services Inc. and the stockholders listed therein	Form S-1/A, filed March 20, 2006, (file no. 333-128750)
10.4	—	Combination Agreement dated as of August 9, 2005, with Complete Energy Services, Inc., I.E. Miller Services, Inc. and Complete Energy Services, LLC and I.E. Miller Services, LLC	Form S-1, filed September 30, 2005, (file no. 333-128750)
10.5	—	Second Amended and Restated Credit Agreement, dated as of December 6, 2006 by and among Complete Production Services, Inc., as U.S. Borrower, Integrated Production Services Ltd., as Canadian Borrower, Wells Fargo Bank, National Association, as U.S. Administrative Agent, U.S. Issuing Lender and U.S. Swingline Lender, HSBC Bank Canada, as Canadian Administrative Agent, Canadian Issuing Lender and Canadian Swingline Lender, and the Lenders party thereto, Wells Fargo Bank, National Association as Lead Arranger and Amegy Bank N.A. and Comerica Bank, as Co-Documentation Agents	Form 10-K, filed March 9, 2007, (file no. 001-32858)
10.6*	—	Integrated Production Services, Inc. 2001 Stock Incentive Plan	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.7*	—	Complete Energy Services, Inc. 2003 Stock Incentive Plan	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.8*	—	First Amendment to Complete Energy Services, Inc. 2003 Stock Incentive Plan	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.9*	—	Second Amendment to Complete Energy Services, Inc. 2003 Stock Incentive Plan	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.10*	—	Amended and Restated Integrated Production Services, Inc. 2003 Parchman Restricted Stock Plan	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.11*	—	Amended and Restated 2001 Stock Incentive Plan	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
10.12*	—	Amendment No. 1 to the Complete Production Services, Inc. Amended and Restated 2001 Stock Incentive Plan	Form 10-K, filed March 9, 2007 (file no. 001-32858)
10.13*	—	I.E. Miller Services, Inc. 2004 Stock Incentive Plan	Form S-1/A, filed November 15, 2005, (file no. 333-128750)

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
10.14 —	Strategic Customer Relationship Agreement	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.15* —	Form of Restricted Stock Grant Agreement (Employee)	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.16* —	Form of Restricted Stock Grant Agreement (Non-employee Director)	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.17* —	Form of Non-Qualified Option Grant Agreement (Executive Officer)	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
10.18* —	Form of Non-Qualified Option Grant Agreement (Non-Employee Director)	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
10.19* —	Compensation Package Term Sheet — James F. Maroney, III	Form S-1/A, filed March 20, 2006, (file no. 333-128750)
10.20* —	Compensation Package Term Sheet — Kenneth L. Nibling	Form S-1/A, filed March 20, 2006, (file no. 333-128750)
10.21* —	Incentive Plan Guidelines for Senior Management	Form 8-K, filed February 22, 2007
10.22* —	Form of Non-qualified Stock Option Grant Agreement	Form 8-K, filed February 2, 2007
10.23* —	Form of Restricted Stock Agreement — Executive Officer (Post-September 2006)	Form 8-K, filed February 2, 2007
10.24* —	Restricted Stock Agreement Terms and Conditions (Revised 2006) — Employee	Form 10-K, filed March 9, 2007, (file no. 001-32858)
10.25* —	Signature Page for Restricted Stock Agreement — Employee	Form 10-K, filed March 9, 2007, (file no. 001-32858)
10.26* —	Non-Employee Director Restricted Stock Agreement	Form 10-K, filed March 9, 2007, (file no. 001-32858)
10.27* —	Stock Option Terms and Conditions (Revised 2006) — Employee	Form 10-K, filed March 9, 2007, (file no. 001-32858)
10.28* —	Signature Page for Executive Officers	Form 10-K, filed March 9, 2007, (file no. 001-32858)
10.29* —	Director Option Agreement	Form 10-K, filed March 9, 2007, (file no. 001-32858)
10.30* —	Form of Executive Agreement	Form 10-Q, filed May 4, 2007, (file no. 001-32858)
10.31* —	Amendment to Employment Agreement, dated March 21, 2007 between Complete Production Services, Inc. and Mr. Joseph C. Winkler	Form 10-Q, filed May 4, 2007, (file no. 001-32858)
10.32* —	Pumpco Services, Inc. 2005 Stock Incentive Plan	Registration Statement on Form S-8, filed March 28, 2007, (file no. 333-141628)
10.33 —	First Amendment to Second Amended and Restated Credit Agreement, dated as of December 6, 2006 by and among Complete Production Services, Inc., as U.S. Borrower, Integrated Production Services Ltd., as Canadian Borrower, Wells Fargo Bank, National Association, as U.S. Administrative Agent, U.S. Issuing Lender and U.S. Swingline Lender, HSBC Bank Canada, as Canadian Administrative Agent, Canadian Issuing Lender and Canadian Swingline Lender, and the Lenders party thereto, Wells Fargo Bank, National Association as Lead Arranger and Amegy Bank N.A. and Comerica Bank, as Co-Documentation Agents, effective June 29, 2007.	Form 10-Q, filed August 3, 2007, (file no. 001-32858)
10.34 —	Second Amendment to Credit Agreement and Omnibus Amendment to Security Documents, dated October 9, 2007 but effective October 19, 2007, among Complete Production Services, Inc., Integrated Production Services, Ltd., Wells Fargo Bank, National Association, as administrative agent, swing line lender and issuing lender and HSBC Bank Canada, as administrative agent, swing line lender and issuing lender.	Form 10-Q, filed November 2, 2007, (file no. 001-32858)
10.35* —	Complete Production Services, Inc. 2008 Incentive Award Plan	Appendix A of Definitive Proxy Statement on Schedule 14, filed April 7, 2008
10.36* —	Form of Non-Qualified Stock Option Agreement	Form 10-Q, filed August 1, 2008, (file no. 001-32858)

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
10.37* —	Agreement for Non-Employee Directors	Form 10-Q, filed August 1, 2008, (file no. 001-32858)
10.38* —	Form of Signature Page for Stock Option Agreement Terms and Conditions	Form 10-Q, filed August 1, 2008, (file no. 001-32858)
10.39* —	Restricted Stock Agreement Terms and Conditions	Form 10-Q, filed August 1, 2008, (file no. 001-32858)
10.40* —	Form of Stock Agreement	Form 10-Q, filed August 1, 2008, (file no. 001-32858)
10.41* —	Signature Page to the Restricted Stock Award Agreement Terms and Conditions	Form 10-Q, filed August 1, 2008, (file no. 001-32858)
10.42* —	Restricted Stock Agreement for Non-Employee Directors	Form 10-Q, filed August 1, 2008, (file no. 001-32858)
10.43* —	Retirement Agreement between Complete Production Services, Inc. and J. Michael Mayer, effective October 7, 2008.	Form 8-K, filed October 9, 2008, (file no. 001-32858)
10.44* —	Complete Production Services, Inc. Deferred Compensation Plan, effective January 1, 2009	Form 10-K, filed February 27, 2009, (file no. 001-32858)
10.45* —	Amended and Restated Employment Agreement, effective December 31, 2008 between Complete Production Services, Inc. and Mr. Joseph C. Winkler	Form 10-K, filed February 27, 2009, (file no. 001-32858)
10.46* —	Form of Amended and Restated Complete Production Services Executive Agreement	Form 10-K, filed February 27, 2009, (file no. 001-32858)
10.47 —	Second Supplemental Indenture among the Guarantor Subsidiaries of Complete Production Services, Inc., and Wells Fargo Bank, National Association, as trustee under the Indenture, dated April 1, 2009	Form 10-Q, filed April 30, 2009 (file no.001-32858)
10.48 —	Third Amendment to Credit Agreement, Omnibus Amendment to Credit Documents and Assignment, dated as of October 13, 2009, among Complete Production Services, Inc., Integrated Production Services Ltd., certain subsidiary guarantors party thereto, the lenders party thereto, Wells Fargo Bank, National Association, Wells Fargo Foothill, LLC and HSBC Bank Canada	Form 8-K, filed October 16, 2009
10.49* —	Retirement Agreement between the Company and Robert L. Weisgarber dated May 15, 2009	Form 8-K, filed May 18, 2009
10.50* —	Amendment No. 1 to the Complete Production Services, Inc. 2008 Incentive Award Plan	Proxy Statement on Schedule 14A, filed May 11, 2009
10.51* —	Complete Production Services, Inc. Amended and Restated Deferred Compensation Plan	Form 10-Q, filed April 30, 2010 (file no. 001-32858)
21.1 —	Subsidiaries of Complete Production Services, Inc.	Filed herewith
23.1 —	Consent of Grant Thornton LLP	Filed herewith
24.1 —	Power of Attorney (included on signature page)	Filed herewith
31.1 —	Certification of Chief Executive Officer Pursuant to Rule 13a — 14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2 —	Certification of Chief Financial Officer Pursuant to Rule 13a — 14 of the Securities and Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
32.1 —	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
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	Filed herewith

Exhibit No.		Exhibit Title	Incorporated by Reference to the Following
101	—	Complete Production Services, Inc. Annual Report on Form 10-K for the year ended December 31, 2010, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Balance Sheets at December 31, 2010 and December 31, 2009, (ii) the Consolidated Statements of Operations for the year ended December 31, 2010, 2009 and 2008, (iii) the Consolidated Stockholders' Equity for the years ended December 31, 2010, 2009, 2008, (iv) the Consolidated Statements of Cash Flows for the years ended December 31, 2010, and December 31, 2009, and (v) the Notes to Consolidated Financial Statements (tagged as blocks of text).	Filed herewith

* Management employment agreements, compensatory arrangements or option plans

Complete Production Services, Inc.

Reconciliation of Modified EBITDA to Adjusted EBITDA and Net Income (Loss)
For the Years Ending December 31, 2004, 2005, 2006, 2007, 2008, 2009 and 2010

($000s)	Year Ended December 31,						
	2004 (unaudited)	2005 (unaudited)	2006 (unaudited)	2007 (unaudited)	2008 (unaudited)	2009 (unaudited)	2010 (unaudited)
Net income (loss)	$ 13,884	$ 53,862	$ 138,498	$ 157,860	$ (89,568)	$ (181,668)	$ 84,158
Plus: interest expense, net	7,471	24,460	39,258	61,003	59,428	56,816	57,347
Plus: tax expense (benefit)	7,148	28,606	70,184	84,833	72,305	(63,088)	51,580
Plus: depreciation and amortization	19,838	46,484	75,902	131,399	181,197	200,732	181,823
Minus: income (loss) from discontinued operations (net of tax expense of $3,673, $5,114, $9,359, $6,890, $3,865, zero and zero, respectively)	8,221	10,466	14,050	11,443	(4,859)	-	-
EBITDA	$ 40,120	$ 142,946	$ 309,792	$ 423,652	$ 228,221	$ 12,792	$ 374,908
Plus: non-controlling interest	4,705	384	(49)	(569)	-	-	-
Plus: impairment loss	-	-	-	13,094	272,006	136,289	-
Adjusted EBITDA	$ 44,825	$ 143,330	$ 309,743	$ 436,177	$ 500,227	$ 149,081	$ 374,908
Plus: loss on non-monetary asset exchange	-	-	-	-	-	4,868	-
Plus: loss on fixed asset and inventory writedown	-	-	-	-	-	9,458	-
Modified EBITDA	$ 44,825	$ 143,330	$ 309,743	$ 436,177	$ 500,227	$ 163,407	$ 374,908

Reconciliation of Adjusted EBITDA to the Most Comparable GAAP Measure—Operating Income (Loss)

($000s)	Year Ended December 31,						
	2004 (unaudited)	2005 (unaudited)	2006 (unaudited)	2007 (unaudited)	2008 (unaudited)	2009 (unaudited)	2010 (unaudited)
Adjusted EBITDA	$ 44,825	$ 143,330	$ 309,743	$ 436,177	$ 500,227	$ 149,081	$ 374,908
Less: depreciation and amortization	19,838	46,484	75,902	131,399	181,197	200,732	181,823
Less: goodwill impairment loss	-	-	-	13,094	272,006	97,643	-
Less: fixed asset and other intangible impairment loss	-	-	-	-	-	38,646	-
Plus: write-off of deferred financing fees	-	3,315	170	-	-	528	-
Operating income (loss)	$ 24,987	$ 100,161	$ 234,011	$ 291,684	$ 47,024	$ (187,412)	$ 193,085

Reconciliation of Modified EBITDA to Adjusted EBITDA and Net Income (Loss)
For the Three Month Periods Ended 12/31/09, 3/31/10, 6/30/10, 9/30/10 and 12/31/10

($000s)	For Quarters Ending,				
	12/31/09 (unaudited)	3/31/10 (unaudited)	6/30/10 (unaudited)	9/30/10 (unaudited)	12/31/10 (unaudited)
Revenue	$ 251,402	$ 309,704	$ 360,245	$ 418,609	$ 472,835
Net income (loss)	(103,475)	(2,762)	15,671	33,030	38,219
Plus: interest expense, net	14,515	14,693	14,665	14,095	13,894
Plus: tax expense (benefit)	(25,952)	(1,342)	9,533	21,056	22,333
Plus: depreciation and amortization	47,262	45,319	45,472	44,805	46,227
EBITDA	$ (67,650)	$ 55,908	$ 85,341	$ 112,986	$ 120,673
Plus: impairment losses	100,131	-	-	-	-
Adjusted EBITDA	$ 32,481	$ 55,908	$ 85,341	$ 112,986	$ 120,673
Plus: loss on fixed asset and inventory writedown	1,955	-	-	-	-
Modified EBITDA	$ 34,436	$ 55,908	$ 85,341	$ 112,986	$ 120,673
Modified EBITDA Margin	*13.7%*	*18.1%*	*23.7%*	*27.0%*	*25.5%*

Management evaluates the performance of Complete's operating segments using non-GAAP financial measures, including Adjusted EBITDA and Modified EBITDA. Adjusted EBITDA is calculated as net income from continuing operations before net interest expense, taxes, depreciation, amortization, impairment charges and minority interest. Modified EBITDA is calculated as Adjusted EBITDA before certain other non-cash charges including fixed asset and inventory write-downs and loss on non-monetary asset exchange. Adjusted EBITDA and Modified EBITDA are not substitutes for GAAP measures of earnings and cash flow. Adjusted EBITDA and Modified EBITDA are used in this annual report because our management considers these measures to be important supplemental measures of performance and believes they are used by securities analysts, investors and other interested parties in the evaluation of companies in our industry.

Adjusted EBITDA and Modified EBITDA, as calculated by us, is different than the calculation of EBITDA under our credit facility (see the notes to our consolidated financial statements in our Annual Report on Form 10-K for a description of the EBITDA calculation under our credit facility).

Complete Production Services, Inc.

Reconciliation of Earnings Per Share Less Impairment Charge to Earmings per Share (Loss)

For the Years Ended December 31, 2004, 2005, 2006, 2007, 2008, 2009 and 2010

	For the Years Ended December 31,						
($000s)	2004 (unaudited)	2005 (unaudited)	2006 (unaudited)	2007 (unaudited)	2008 (unaudited)	2009 (unaudited)	2010 (unaudited)
Net income (loss) from continuing operations, as reported	$ 5,663	$ 43,396	$ 124,448	$ 146,417	$ (84,709)	$ (181,668)	$ 84,158
Add: Impairment charge	-	-	-	13,094	272,006	136,289	-
Add: Loss on non-monetary asset exchange	-	-	-	-	-	4,868	-
Add: Loss on fixed asset and inventory writedown	-	-	-	-	-	9,458	-
Less: Tax benefit recognized from goodwill impairment	-	-	-	-	(19,030)	(26,916)	-
Net income (loss) from continuing operations less impairment charge	$ 5,663	$ 43,396	$ 124,448	$ 159,511	$ 168,267	$ (57,969)	$ 84,158
Net income (loss) from discontinued operations, as reported	8,221	10,466	14,050	11,443	(4,859)	-	-
Net income (loss) less impairment charge	$ 13,884	$ 53,862	$ 138,498	$ 170,954	$ 163,408	$ (57,969)	$ 84,158
Basic weighted average shares outstanding, as reported	29,548	46,603	65,843	71,991	73,600	75,095	76,048
Add: Dilutive securities:							
Stock options	535	743	1,613	1,078	649	-	759
Restricted shares	-	486	313	283	306	-	877
Stock warrants	-	2,824	-	-	-	-	-
Contingent shares*	-	-	306	-	-	-	-
Adjusted diluted weighted average shares	30,083	50,656	68,075	73,352	74,555	75,095	77,684
Diluted earnings (loss) per share, as reported:							
Continuing operations	$ 0.19	$ 0.87	$ 1.83	$ 2.00	$ (1.15)	$ (2.42)	$ 1.08
Discontinued operations	$ 0.27	$ 0.19	$ 0.21	$ 0.15	$ (0.07)	$ -	$ -
	$ 0.46	$ 1.06	$ 2.04	$ 2.15	$ (1.22)	$ (2.42)	$ 1.08
Adjusted diluted earnings (loss) per share less impairment charge:							
Continuing operations	$ 0.19	$ 0.87	$ 1.83	$ 2.17	$ 2.26	$ (0.77)	$ 1.08
Discontinued operations	$ 0.27	$ 0.19	$ 0.21	$ 0.15	$ (0.07)	$ -	$ -
	$ 0.46	$ 1.06	$ 2.04	$ 2.32	$ 2.19	$ (0.77)	$ 1.08

* Contingent shares represent potential common stock issued on March 16, 2006 in conjunction with earn-out agreements for two businesses acquired in 2005. Actual shares issued pursuant to these agreements was 1,214 shares.

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MANAGEMENT

JOSEPH C. WINKLER
Chairman and Chief Executive Officer

BRIAN K. MOORE
President and Chief Operating Officer

JOSE A. BAYARDO
Senior Vice President
and Chief Financial Officer

JAMES F. MARONEY III
Vice President, Secretary
and General Counsel

KENNETH L. NIBLING
Vice President, Human Resources
and Administration

DEWAYNE WILLIAMS
Vice President,
Accounting and Controller

RONALD BOYD
President, West Division

JEFFREY KAUFMANN
President, East Division

DAVID NIGHTINGALE
President, IE Miller Division

RONNY ORTOWSKI
President, Pumpco Division

MARK SONGER
President, Appalachian Division

BRYAN SUPRENANT
President, IPS Division

DIRECTORS

JOSEPH C. WINKLER
Chairman and Chief Executive Officer
Complete Production Services

ROBERT S. BOSWELL
Chairman and Chief Executive Officer
Laramie Energy II, LLC

HAROLD G. HAMM
Chairman and Chief Executive Officer
Continental Resources, Inc.

MICHAEL M. MCSHANE
Retired Chairman, President
and Chief Executive Officer
Grant Prideco, Inc.

W. MATT RALLS
President and Chief Executive Officer
Rowan Companies, Inc.

MARCUS A. WATTS
President
Friedkin Group, Inc.

JAMES D. WOODS
Chairman Emeritus and
retired Chief Executive Officer
Baker Hughes Incorporated

STOCK LISTING

New York Stock Exchange
Symbol: CPX

FORM 10-K

A copy of the Company's Annual Report to the Securities and Exchange Commission (Form 10-K) is available by writing to:
Investor Relations
Complete Production Services, Inc.
11700 Katy Freeway, Suite 300
Houston, TX 77079

ANNUAL MEETING

The Company's Annual Meeting of Stockholders will be held at 9:00 am on May 25, 2011, at:
The St. Regis Hotel
1919 Briar Oaks Lane
Houston, TX 77027

FINANCIAL INFORMATION AND NEWS RELEASES

Information updates about us, including quarterly financial results and current news releases, are available to the public on our Web site at www.completeproduction.com or upon request from our Investor Relations department.

STOCK TRANSFER AGENT AND REGISTRAR

Wells Fargo Shareowner Services
161 North Concord Exchange
South St. Paul, MN 55075
(800) 468-9716
https://www.wellsfargo.com/shareownerservices

CORPORATE GOVERNANCE CERTIFICATION

Complete Production Services has filed the certification of its Chief Executive Officer and Chief Financial Officer, and each has signed and filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 with its Annual Report on Form 10-K.

INDEPENDENT AUDITORS

Grant Thornton LLP
Houston, TX

Complete Production Services, Inc.
11700 Katy Freeway, Suite 300
Houston, TX 77079