Complete Production Services, Inc.
Form 10-K
February 29, 2008

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

Form 10-K

(MARK ONE)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **FOR THE FISCAL YEAR ENDED DECEMBER 31, 2007**
o	**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 Old Katy Road, 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-know seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

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

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

Indicate by check mark 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. o

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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting Company o

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

As of June 29, 2007, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $1,131,199,981 based upon the price at which our common stock was last sold on that date.

Number of shares of the Common Stock of the registrant outstanding as of February 15, 2008: 73,447,772

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s proxy statement to be furnished to the stockholders in connection with its 2008 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, 2007 (this Annual Report).

Complete Production Services, Inc.

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PART I

Unless otherwise indicated, all references to we, us, our, our company, or Complete include Complete Producti 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 provide specialized services and products focused on helping oil and gas companies develop hydrocarbon reserves, reduce 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 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 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, Kansas, western Canada and Mexico. We also have operations in Southeast Asia.

The Combination

Prior to 2001, SCF Partners, a private equity firm that focuses on investments in the oilfield services segment of the energy industry, began to target investment opportunities in service oriented companies in the North American natural gas market with specific focus on the completion and production phase of the exploration and production cycle. On May 22, 2001, SCF Partners through a limited partnership, SCF-IV, L.P. (SCF), formed Saber, a new company, in connection with its acquisition of two companies primarily focused on completion and production related services in Louisiana. In July 2002, SCF became the controlling stockholder of Integrated Production Services, Ltd., a production enhancement company that, at the time, focused its operation in Canada. In September 2002, Saber acquired this company and changed its name to Integrated Production Services, Inc. (IPS). Subsequently, IPS began to grow organically and through several acquisitions, with the ultimate objective of creating a technical leader in the enhancement of natural gas production. In November 2003, SCF formed another production services company, Complete Energy Services, Inc. (CES), establishing a platform from which to grow in the Barnett Shale region of north Texas. Subsequently, through organic growth and several acquisitions, CES extended its presence to the U.S. Rocky Mountain and the Mid-continent regions. In the summer of 2004, SCF formed I.E. Miller Services, Inc. (IEM), which at the time had a presence in Louisiana and Texas. During 2004, IPS and IEM independently began to execute strategic initiatives to establish a presence in both the Barnett Shale and U.S. Rocky Mountain regions.

On September 12, 2005, IPS, CES and IEM were combined and became Complete Production Services, Inc. in a transaction we refer to as the Combination. In the Combination, IPS served as the acquirer. Immediately after the Combination, SCF held approximately 70% of our outstanding common stock, the former CES stockholders (other than SCF) in the aggregate held approximately 18.8% of our outstanding common stock, the former IEM stockholders (other than SCF) in the aggregate held approximately 2.4% of our outstanding common stock and the former IPS stockholders (other than SCF) in the aggregate held approximately 8.4% of our outstanding common stock.

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.

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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 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. We also offer several proprietary services and products that we believe create significant value for our customers.

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, specialized rig logistics and site preparation throughout our service area. Our drilling rigs currently operate exclusively in and around the Barnett Shale region of north Texas.

Product Sales. Through our product sales segment, we provide a variety of equipment used by oil and gas companies throughout the lifecycle of their wells. We sell a full range of oilfield supplies, as well as tubular goods, throughout the United States (north Texas, Louisiana, Arkansas, Oklahoma and the Rocky Mountains), primarily through our supply stores. We also sell products through our Southeast Asia business and through agents in markets outside of North America.

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. Our business is primarily driven by natural gas drilling activity in North America. We believe the following two principal economic factors will positively affect our industry in the coming years:

Higher demand for natural gas in North America. We believe that natural gas will be in high demand in North America over the next several years because of the growing popularity of this clean-burning fuel. According to the International Energy Association s Energy Outlook 2007, natural gas demand and consumption in North America (United States, Canada and Mexico) is projected to grow through 2020 and remain relatively constant from 2020 through 2030. Overall energy use worldwide is expected to grow by 57% through 2030, with liquid fuels produced from natural gas and other sources accounting for 9% of the world s liquid fuels supply.

Constrained North American gas supply. Although the demand for natural gas is projected to increase, supply is likely to be constrained as North American natural gas basins are becoming more mature and experiencing increased decline rates. Even though the number of wells drilled in North America has increased significantly in recent years, a corresponding increase in domestic production has not occurred. As a result, producers are required to increase drilling just to maintain flat production. To supply the growing demand for natural gas, the primary alternatives are to increase drilling, enhance recovery rates or import LNG from overseas. To date minimal increases have occurred, although many forecasts anticipate a material increase of LNG imports in the future.

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As a result of the above factors, we expect there to be a long-term tight supply of, and high demand for, natural gas in North America. We believe this will continue to support high natural gas prices and high levels of drilling activity.

As illustrated in the table below, natural gas prices have risen over recent years with some volatility between years, while oil prices have increased steadily due to worldwide demand for energy and other global and domestic economic factors. During 2006, natural gas prices decreased from record levels due to short-term oversupply in the market, but still remained high compared to historical averages and increased again in 2007. The price of a barrel of crude oil reached an all-time high during 2007 and continued to increase into early 2008. The number of drilling rigs under contract in the United States and Canada and the number of well service rigs have increased over the three-year period ended December 31, 2007, according to Baker Hughes Incorporated (BHI). 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 1999:

Period		**Average Daily Closing Henry Hub Spot Natural Gas Prices ($/mcf)**	**Average Daily Closing WTI Cushing Spot Oil Price ($/bbl)**
1/1/99	12/31/99	$ 2.27	$ 19.30
1/1/00	12/31/00	4.31	30.37
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

Source: Bloomberg NYMEX prices.

Continued demand for natural gas and a constrained gas supply have resulted in higher prices and increased drilling activity. The increase in prices and drilling activity are driving the following long-term trends that we believe will benefit us:

Trend toward drilling and developing unconventional North American natural gas resources. Due to the maturity of conventional North American oil and gas reservoirs and their accelerating production decline rates, unconventional oil and gas resources will comprise an increasing proportion of future North American oil and gas production. Unconventional resources include tight sands, shales and coalbed methane. These resources require more wells to be drilled and maintained, frequently on tighter acreage spacing. 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 and Equipment. Increasing prices and the development of unconventional oil and gas resources are driving the need for complex, new technologies and equipment to help increase recovery rates, lower production costs and accelerate field development.

Although we believe the long-term fundamentals for increased demand for natural gas are positive, natural gas prices will be impacted by the ability to move gas from producing areas to consuming areas of North America. As a result of a significant level of natural gas drilling in western Colorado and southwest Wyoming, pipeline capacity became constrained in late 2006 and continued into 2007, contributing to a decline in natural gas prices in these areas. Major new pipeline capacity in this area is expected to be available in the first half of 2008 which could partially alleviate pricing pressures in the Rocky Mountain area.

Natural gas is generally placed into storage during the warmer months of the year and withdrawn during colder months. The amount of natural gas in storage can impact current natural gas prices and prices quoted on futures exchanges for future periods. These fluctuations in pricing can impact the level of drilling activity by our customers as they adjust investment levels commensurate with their revenues.

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:

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 gas plays we believe have the potential for long-term growth. Our position in these basins capitalizes on our strong local leadership that has 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 gas 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 sell new services and products to customers 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. We employ a rigorous acquisition screening process and have developed comprehensive post-acquisition integration capabilities designed to ensure each acquisition is effectively assimilated. We use a returns method for evaluating capital investment opportunities, and we apply a disciplined approach to adding new equipment.

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 quality of service by focusing on the following:

- clear business direction;
- thorough planning process;
- clearly defined targets and accountabilities;
- close performance monitoring;
- safety objectives;

strong performance incentives for management and employees; and

effective communication.

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 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 bring their expertise to bear while selling services and products to our customers. We strive to leverage this basin-level 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, Kansas and Oklahoma, western Canada and Mexico, with concentrations in key resource plays and unconventional basins. Resource plays are expected to become increasingly important 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 Barnett Shale region of north Texas, the Fayetteville Shale in Arkansas, the Woodford Shale in Oklahoma and the Piceance Basin in Colorado, for example. 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 and 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 the downtime and associated expenditures and enables the 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 new platforms obtained through targeted acquisitions.

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, implementing corporate governance procedures and overseeing 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

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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 17 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**	**East Texas**	**Gulf Coast/ South Louisiana**	**Central & Western Oklahoma**	**Eastern Oklahoma & Arkansas**	**DJ Basin (CO)**	**Western Slope (CO & UT)**	**Wyoming**	**North rockies (MT & ND)**	**Western Canadian Sedimentary Basin**	**Mexico**
Completion and Production Services:												
Coiled Tubing	ü	ü	ü	ü	ü	ü			ü			ü
Pressure Pumping	ü											
Well Servicing	ü	ü	ü		ü	ü	ü	ü	ü	ü		
Snubbing	ü	ü							ü			
Electric-line	ü			ü	ü	ü	ü		ü		ü	
Slickline		ü	ü								ü	ü
Production Optimization	ü	ü	ü		ü	ü		ü	ü		ü	
Production Testing		ü					ü	ü	ü		ü	ü
Rental Equipment	ü		ü		ü	ü	ü	ü	ü	ü		
Pressure Testing								ü	ü			ü
Fluid Handling	ü	ü	ü		ü	ü	ü	ü	ü	ü		
Drilling Services:												
Contract Drilling	ü											
Drilling Logistics	ü	ü	ü	ü	ü	ü		ü		ü		
Product Sales:												
Supply Stores	ü		ü			ü	ü	ü				

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

Completion and Production Services (76% of Revenue for the Year Ended December 31, 2007)

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 good 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 the above services are as follows:

Coiled Tubing 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 foam washing, acidizing, displacing, cementing, gravel packing, plug drilling, 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 Wyoming, Oklahoma, Texas, Louisiana, Arkansas, Mexico and offshore in the Gulf of Mexico.

Pressure Pumping Services

We operate a fleet of pressure pumping equipment in the Barnett Shale of north Texas through which we provide stimulation and cementing services principally to natural gas drilling and producing companies.

Stimulation services primarily consist of hydraulic fracturing of hydrocarbon bearing formations having permeability that restricts the natural flow. The fracturing process consists of pumping fluids into a cased 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 rebuilt over the past five years. We believe we have a leading market position in the Barnett Shale region of north Texas 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, 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.

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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 and Wyoming.

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. Truck and skid mounted 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, Oklahoma, Texas, Kansas, Louisiana and offshore in the Gulf of Mexico.

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 the formation fluid to flow into the wellbore and be produced to the surface. 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 paper 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 run 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 result from liquid loading, reduced bottom-hole pressures or improper well-bore 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. 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.

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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.

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.

We offer production optimization services to customers across the United States and in Canada. We provide production optimization services in Canada through our subsidiary, Premier Production Services Ltd.

Production Testing Services. Production testing is a service required by exploration and production companies to evaluate and clean out new and existing wells. We use a proprietary technology and service approach and are a leading independent provider in North America. We provide production testing services throughout the western Canadian Sedimentary Basin and also 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 a well s or reservoir s production capability. Exploration testing jobs can last from a few days to several months; and

In-line production testing measures a well s 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 find it uneconomical to maintain complete inventories of tools, drillpipe, pressure testing equipment and other specialized equipment and to retain the qualified personnel to operate this equipment. 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, and other equipment, including 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, pipe recovery 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, 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, 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 and Texas and one produced water 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. In addition, we operated two mud disposal facilities that are used to store and ultimately dispose of drilling mud.

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 (15% of Revenue for the Year Ended December 31, 2007)

Through our drilling services segment, we deliver services that initiate or stimulate oil and gas production by providing land drilling, specialized rig logistics and site preparation. Our drilling rigs currently operate in and around the Barnett Shale region of north Texas.

Contract Drilling

We provide contract drilling services to major oil companies and independent oil and gas producers in north 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 have depth ratings ranging from approximately 8,000 to 15,000 feet. We placed into service several land drilling rigs during 2006. We invested in two drilling rigs during

2007.

Drilling Logistics

We provide a variety of drilling logistic services as follows:

Drilling Rig Moving. Through our owned and operated fleet of specialized trucks, we provide drilling rig mobilization services primarily in Louisiana, Texas, Oklahoma, Arkansas and Colorado. 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.

Wellsite Preparation and Remediation. We provide equipment and services to build and reclaim drilling wellsites before and after the drilling operations take place. We build roads, dig pits, clear land, move earth and provide a host of construction services to drilling contractors and to oil and gas producers. Our wellsite preparation and remediation services are in Texas, Colorado and Wyoming.

Product Sales (9% of Revenue for the Year Ended December 31, 2007)

Through our product sales segment, we provide a variety of equipment used by oil and gas companies throughout the lifecycle of their wells. We sell a full range of oilfield supplies, as well as tubular goods, throughout the United States (north Texas, Louisiana, Arkansas, Oklahoma and the Rocky Mountains), primarily through our supply stores. We also sell products through agents in markets outside of North America.

Supply Stores

We own and operate supply stores that provide products and services to the oil and gas industry. We have supply stores and sales offices in Texas, Colorado, Louisiana and Oklahoma. We market tubular products, drill pipe, flow control and completion equipment, valves, fittings and other oilfield products.

Overseas Operations

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 also have a small corporate sales team located in Houston, Texas that supplements our field sales efforts and focuses on large accounts and selling technical services.

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 42%, 37% and 35% of our revenue for the years ended December 31, 2007, 2006 and 2005, respectively, with no one customer representing more than 10% of our revenue for each of these years or in the aggregate. We believe we have a broad customer base and wide geographic coverage of operations, which somewhat insulates us from regional or customer specific circumstances.

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, commercial crime and kidnap and ransom 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., BJ Services Company, Halliburton Company, Weatherford International Ltd., Baker Hughes Inc., Key Energy Services, Inc., Basic Energy Services, Inc., Superior Energy Services, Inc., W-H Energy Services, Inc., 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 and Helmerich & Payne, Grey Wolf Inc. Our principal competitors in our product sales segment include National Oilwell Varco, Inc., Smith International, 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 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 foreign, federal, state and local 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 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, that 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 or arranged for 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.

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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.

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, 2007, we had 7,062 employees. Of our total employees, 6,407 were in the United States, 368 were in Canada, 211 were in Mexico and 76 were in Singapore and other locations in the Far East. 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 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.

You can also obtain information about us at the New York Stock Exchange (NYSE) internet site (www.nyse.com). The NYSE requires the chief executive officer of each listed company to certify annually that he is not aware of any violation by the Company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. Our chief executive officer submitted such an unqualified annual certification to the NYSE in 2007.

Forward-looking Statements

This Annual Report contains certain forward-looking statements within the meaning of the federal securities laws based on our current expectations, assumptions, estimates and projections about us and the oil and gas industry. The words believe, may, will, estimate, continue, anticipate, intend, plan, expect and similar expressions forward-looking statements, although not all forward-looking statements contain these identifying words. All statements other than statements of current or historical fact contained in this Annual Report are forward-looking statements and, as such, 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 stated. For examples of those risks and uncertainties, see the cautionary statements contained 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 17 Segment Reporting for financial information about each of our business segments.

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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:

- 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;
- general economic and market conditions;
- our access to current or future financing arrangements;
- our ability to replace or add workers at economic rates;
- environmental and other governmental regulations; 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 Securities and Exchange Commission, 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;

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- 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 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 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. Any prolonged substantial reduction in oil and gas prices would likely affect oil and gas production levels and therefore affect demand for the services we provide. A material decline in oil and gas prices or North American activity levels could 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. Oil commodity prices reached historic highs in 2007, while natural gas prices peaked in early 2006, then declined substantially later in 2006 and remained relatively stable throughout 2007. General increases in pricing over the last few years have caused oil and gas companies and drilling contractors to change their strategies and expenditure levels, which has benefited us. However, the recent decline in oil and gas prices may result in a decrease in the expenditure levels of oil and gas companies and drilling contractors which would in turn adversely affect 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 changes in oil and gas prices. We reported a loss in 2002, and our income from continuing operations for the years ended December 31, 2007, 2006 and 2005 was $161.6 million, $137.3 million and $50.9 million, respectively.

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.

There is potential for excess capacity in our industry.

Because oil and gas prices and drilling activity have been at historically high levels, oilfield service companies have been acquiring new equipment to meet their customers increasing demand for services. This could result in an increased competitive environment for oilfield service companies, which could lead to lower prices and utilization for our services and could adversely affect our business.

We may be unable to employ 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. A significant increase in the wages paid by competing employers 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 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 operating history may not be sufficient for investors to evaluate our business and prospects.

We are a company with a short combined operating history. In addition, two of our combining companies, IPS and CES, have grown significantly over the last few years through acquisitions. This may make it more difficult for investors to evaluate our business and prospects and to forecast our future operating results. Our historical combined financial statements are based on the separate businesses of IPS, CES and IEM for the periods prior to the Combination. As a result, the historical and pro forma information may not give you an accurate indication of what our actual results would have been if the Combination had been completed at the beginning of the periods presented or of what our future results of operations are likely to be. Our future results will depend on our ability to efficiently manage our combined operations and execute our business strategy.

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, which was exchanged for public debt with substantially identical terms in July 2007, 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.

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. 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 27%, 23% and 23% of our revenue for the years ended December 31, 2007, 2006 and 2005, respectively. Although no single customer accounted for more than 10% of our revenue during the years ended December 31, 2007, 2006 and 2005, our top ten customers represented approximately 42%, 37% and 35% of our revenue for the years then ended. 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.

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

As of December 31, 2007, our long-term debt, including current maturities, was $826.7 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 level of debt increases 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.

Our business depends upon our ability to obtain key raw materials and specialized equipment from suppliers.

Should our current suppliers be unable to provide the necessary raw materials 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 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 acquire additional business opportunities, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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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 Complete s overall safety record, they may not be successful in doing so.

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

On January 1, 2007, we began a self-insurance program to pay claims associated with the health care benefits provided to certain of our employees in the United States. Under this program, we continue to use the insurance company which provided our coverage in the prior year to administer the program, and we have purchased a stop-loss policy with this provider which will 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 our administrator, which facilitates the payment of claims to the medical care providers. As our business grows, we are 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 through our supply stores, 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.

We are subject to extensive and costly environmental laws and regulations that may require us to take actions that will adversely affect our results of operations.

Our business is significantly affected by stringent and complex foreign, federal, state and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. As part of our business, we handle, transport, and dispose of a variety of fluids and substances used or produced by our customers in connection with their oil and gas exploration and production activities. We also generate and dispose of hazardous waste. The generation, handling, transportation, and disposal of these fluids, substances, and waste are regulated by a number of laws, including 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. Failure to properly handle, transport, or dispose of these materials or otherwise conduct our operations in accordance with these and other environmental laws could expose us to liability for governmental penalties, cleanup costs associated with releases of such materials, damages to natural resources, and other damages, as well as potentially impair our ability to conduct our operations. We could be exposed to liability for cleanup costs, natural resource damages and other damages under these and other environmental laws as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, prior operators or other third parties. Environmental laws and regulations have changed in the past, and they are likely to change in the future. If existing regulatory requirements or enforcement policies change, we may be required to make significant unanticipated capital and operating expenditures.

Any failure by us to comply with applicable environmental laws and regulations may result in governmental authorities taking actions against our business that could adversely impact our operations and financial condition, including the:

- issuance of administrative, civil and criminal penalties;
- denial or revocation of permits or other authorizations;
- imposition of limitations on our operations; and
- performance of site investigatory, remedial or other corrective actions.

The effect of environmental laws and regulations on our business is discussed in greater detail under Environmental Matters included in Item 1 of this Annual Report on Form 10-K.

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

Our business is significantly affected by state and federal laws and other regulations relating to the oil and gas industry in general, and more specifically with respect to health and safety, waste management and the manufacture, storage, handling and transportation of hazardous materials and by changes in and the level of enforcement of such laws. The failure to comply with these rules and regulations can result in substantial penalties, revocation of permits, corrective action orders and criminal prosecution. The regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability. We may be subject to claims alleging personal injury or property damage as a result of alleged exposure to hazardous substances. It is impossible for management to predict the cost or impact of such laws and regulations on our future operations.

If we fail to develop or 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 continue to develop and 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 develop or maintain effective controls or to make effective improvements to our internal controls could harm our operating results.

A terrorist attack or armed conflict could harm our business.

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

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 the years ended December 31, 2007, 2006 and 2005, our Canadian operations represented approximately 5%, 7% and 9% of our revenue from continuing operations. For the years ended December 31, 2006 and 2005, our Canadian operations represented 3% and 4% of our net income from continuing operations before taxes and minority interest, respectively. Our Canadian operations recorded a loss from continuing operations before taxes and minority interest of $13.5 million for the year ended December 31, 2007.

We are susceptible to seasonal earnings volatility due to adverse weather conditions in Canada.

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 frost leaves the ground 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.

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.

Our business in Mexico is substantially all performed for PEMEX pursuant to multi-year contracts. These contracts are generally two years in duration and are subject to competitive bid for renewal. Any failure by us to renew our contracts could have a material adverse effect on our financial condition, results of operations and cash flows.

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 made effective as of October 2007 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.

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Our U.S. operations are adversely impacted by the hurricane season in the Gulf of Mexico, which generally occurs in the third calendar quarter.

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.

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 significant 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 reach 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 increase significantly our earnings volatility with respect to rig relocation.

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

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. 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 state safety regulations that mirror federal regulations. Such matters as weight and dimension of equipment are also subject to federal and state regulations.

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.

Risks Related to Our Relationship with SCF

L.E. Simmons, through SCF, may be able to control the outcome of stockholder voting and may exercise this voting power in a manner adverse to you.

SCF owns approximately 23% of our outstanding common stock (this percentage does not include shares distributed by SCF to its partners). L.E. Simmons is the sole owner of L.E. Simmons and Associates, Incorporated, the ultimate general partner of SCF. Accordingly, Mr. Simmons, through his ownership of the ultimate general partner of SCF, may be in a position to control the outcome of matters requiring a stockholder vote, including the election of directors, adoption of amendments to our certificate of incorporation or bylaws or approval of transactions involving a change of control. The interests of Mr. Simmons may differ from yours, and SCF may vote its common stock in a manner that may adversely affect you.

One of our directors may have a conflict of interest because he is affiliated with SCF. The resolution of this conflict of interest may not be in our or your best interests.

One of our directors, Andrew L. Waite, is a current officer of L.E. Simmons and Associates, Incorporated, the ultimate general partner of SCF. This may create a conflict of interest because this director has responsibilities to SCF and its owners. His duties as an officer of L.E. Simmons and Associates, Incorporated may conflict with his duties as a director of our company regarding business dealings between SCF and us and other matters. The resolution of this conflict may not always be in our or your best interests.

We have renounced any interest in specified business opportunities, and SCF and its director nominees on our board of directors generally have no obligation to offer us those opportunities.

SCF has investments in other oilfield service companies that may compete with us, and SCF and its affiliates, other than our company, may invest in other such companies in the future. We refer to SCF and its other affiliates and its portfolio companies as the SCF group. Our certificate of incorporation provides that, so long as we have a director or officer that is affiliated with SCF (an SCF Nominee), we renounce any interest or expectancy in any business opportunity in which any member of the SCF group participates or desires or seeks to participate in and that involves any aspect of the energy equipment or services business or industry, other than (i) any business opportunity that is brought to the attention of an SCF Nominee solely in such person s capacity as a director or officer of our company and with respect to which no other member of the SCF group independently receives notice or otherwise identifies such opportunity and (ii) any business opportunity that is identified by the SCF group solely through the disclosure of information by or on behalf of our company. We are not prohibited from pursuing any business opportunity with respect to which we have renounced any interest.

Risks Related to Our Senior Notes

We may not be able to generate sufficient cash to service all of our indebtedness, including the notes, and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments or to refinance our debt obligations depends on our financial and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We cannot assure you that we will maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay capital expenditures, sell assets or operations, seek additional capital or restructure or refinance our indebtedness, including the notes. We cannot assure you that we would be able to take any of these actions, that these actions would be successful and permit us to meet our scheduled debt service obligations or that these actions would be permitted under the terms of our existing or future debt agreements including our amended revolving credit facility and the indenture that will govern the notes. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our amended revolving credit facility and the indenture that will govern the notes will restrict our ability to dispose of assets and use the proceeds from the disposition. We may not be able to consummate those dispositions or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due.

If we cannot make scheduled payments on our debt, we will be in default and, as a result:

- our debt holders could declare all outstanding principal and interest to be due and payable;

the lenders under our amended revolving credit facility could terminate their commitments to loan us money and foreclose against the assets securing their borrowings; and

we could be forced into bankruptcy or liquidation, which could result in the loss of your investment in the notes.

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 specified financial ratios and satisfy other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those tests. 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. 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.

Our borrowings under our amended revolving credit facility are, and are expected to continue to be, at variable rates of interest and 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.

If we default on our obligations to pay our indebtedness we may not be able to make payments on our senior notes.

Any default under the agreements governing our indebtedness, including a default under our amended revolving credit facility that is not waived by the required lenders, and the remedies sought by the holders of such indebtedness, could render us unable to pay principal, premium, if any, and interest on the notes and substantially decrease the market value of the notes. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness (including covenants in our amended revolving credit facility), we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders under our amended revolving credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation. If our operating performance declines, we may in the future need to obtain waivers from the required lenders under our amended revolving credit facility to avoid being in default. If we breach our covenants under our amended revolving credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under our amended revolving credit facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

We may incur substantially more debt. This could further exacerbate the risks described above.

We and our subsidiary guarantors may be able to incur substantial additional indebtedness in the future. The terms of the indenture do not fully prohibit us or our subsidiary guarantors from doing so. If we incur any additional indebtedness, including trade payables, that ranks equally with the notes, the holders of that debt will be entitled to share ratably with the holders of the notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding up of our company. This may have the effect of reducing the amount of proceeds available to repay the notes. We have a $400 million revolving credit facility with approximately $190.0 million of undrawn availability as of December 31, 2007. All of those borrowings will be secured by substantially all of our assets and will rank effectively senior to the notes and the guarantees. If new debt is added to our current debt levels, the related risks that we and our subsidiary guarantors now face could intensify. The subsidiaries that guarantee our senior notes will also be guarantors under our amended revolving credit facility.

As a holding company, Complete s main source of cash is distributions from its subsidiaries.

We conduct our operations primarily through our subsidiaries, and these subsidiaries directly own substantially all of our operating assets. Therefore, our operating cash flow and ability to meet our debt obligations depend principally on the cash flow provided by our subsidiaries in the form of loans, dividends or other payments to us as an equity holder, service provider or lender. The ability of our subsidiaries to make such payments to the parent company will depend on their earnings, tax considerations, legal restrictions and contractual restrictions imposed by their own indebtedness. Although our debt facilities limit the right of certain of our subsidiaries to enter into consensual restrictions on their ability to pay dividends and make other payments to us, these limitations are subject to a number of significant qualifications and exceptions.

In addition, not all of our subsidiaries guarantee our obligation under the senior notes. Creditors of such subsidiaries (including trade creditors) generally will be entitled to payment from the assets of those subsidiaries before those assets can be distributed to us. As a result, our senior notes are effectively subordinated to the prior payment of all of the debts (including trade payables) of our non-guarantor subsidiaries.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

As of December 31, 2007, we owned 52 offices, facilities and yards, of which 11 were in Texas, 22 were in Oklahoma, two were in Arkansas, one was in North Dakota, one was in Montana, six were in Wyoming, three were in Colorado, three were in Louisiana, one was in Alberta, Canada, one was in Utah and one was in Poza Rica, Mexico. As of December 31, 2007, we owned 62 saltwater disposal wells, of which 28 were in Texas, 31 were in Oklahoma and three were in Arkansas. In addition, we owned one drilling mud disposal facility in Oklahoma and one produced water evaporation facility in Wyoming.

In addition, as of December 31, 2007, we leased 258 offices, facilities and yards, of which 85 were in Texas, 33 were in Oklahoma, 27 were in Wyoming, two were in Montana, four were in North Dakota, 29 were in Colorado, six were in Louisiana, nine were in Arkansas, seven were in Kansas, seven were in Utah, 34 were in Alberta, Canada, two were in British Columbia, Canada, four were in Mexico and nine were in Singapore. As of December 31, 2007, we leased two drilling mud disposal facilities in Oklahoma.

In addition, we also leased our corporate headquarters in Houston, Texas, as well as administrative offices in Gainesville, Texas; Enid, Oklahoma; Fredrick, Colorado; Eunice, Louisiana; 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.

At June 30, 2007, we had accrued $1.6 million in additional insurance premium related to a cost-sharing provision of our general liability policy, of which we paid $1.4 million in August 2007. Although we do not believe it is probable that we will incur additional costs pursuant to this provision, 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. ***Submission of Matters to a Vote of Security Holders.***

None.

PART II

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

We have 200,000,000 authorized shares of $0.01 par value common stock, of which 73,135,382 shares were outstanding at December 31, 2007, including 625,871 shares of non-vested restricted stock for which the forfeiture restrictions have not lapsed. At February 15, 2008, we had 73,447,772 shares of common stock outstanding, of which 913,371 shares were non-vested restricted stock subject to forfeiture restrictions. The common shares outstanding at February 15, 2008 were held by 117 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, 2007 or February 15, 2008.

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.

The following table presents the high and low sales prices of our common stock reported by the New York Stock Exchange for the period April 20, 2006 through June 30, 2006, the calendar quarters ended September 30, 2006 and December 31, 2006, and for each calendar quarters in 2007:

	CPX Stock Price	
Period	**High**	**Low**
Period from April 20, 2006 to June 30, 2006	$ 28.43	$ 20.75
Quarter ended September 30, 2006	$ 24.75	$ 18.75
Quarter ended December 31, 2006	$ 23.15	$ 17.20
Quarter ended March 31, 2007	$ 21.20	$ 17.28
Quarter ended June 30, 2007	$ 27.75	$ 19.45
Quarter ended September 30, 2007	$ 26.17	$ 20.00
Quarter ended December 31, 2007	$ 22.66	$ 17.30

The year-end closing sales price of our Common Stock was $21.20 on December 29, 2006, the last trading day of 2006, and $17.97 on December 31, 2007, the last trading day of 2007.

Issuer Purchases of Equity Securities:

We made no repurchases of our common stock during the years ended December 31, 2007 or 2006.

Dividends:

On September 12, 2005, we paid a dividend of $2.62 per share for an aggregate payment of approximately $146.9 million to stockholders of record on that date. 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.

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Performance Graph:

The following information in this Item 5 of this Annual Report is not deemed to be soliciting material or to be filed with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Security Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

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, 2007. 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 20 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 on 3/31/06 in index-including reinvestment of dividends. Fiscal year ending December 31.

www.researchdatagroup.com/S&P.htm

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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, 2003 has been derived from our consolidated financial statements. The selected consolidated financial data as of December 31, 2004, 2005, 2006 and 2007 and for each of the years then ended have been derived from our audited consolidated financial statements for those dates and periods. 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 in this Annual Report.

	For the Year Ended December 31,				
	2003	2004	2005(3)	2006	2007
	(In thousands)				
Statement of Operations Data:					
Revenue:					
Completion and production services	$ 65,025	$ 194,953	$ 510,304	$ 873,493	$ 1,262,100
Drilling services	2,707	44,474	129,117	215,255	240,377
Products sales(1)	16,653	54,483	80,768	123,676	152,760
Total	84,385	293,910	720,189	1,212,424	1,655,237
Expenses:					
Service and product expenses(2)	58,185	194,645	450,718	710,961	980,262
Selling, general and administrative	14,660	44,002	108,766	167,334	210,147
Depreciation and amortization	7,482	21,327	48,510	79,465	135,961
Operating income (loss) from continuing operations before interest, taxes and minority interest	4,058	33,936	112,195	254,664	328,867
Write-off of deferred financing fees			3,315	170	
Impairment loss(4)					13,094
Interest expense	2,683	7,471	24,460	40,759	62,673
Interest income				(1,387)	(1,636)
Taxes	827	10,504	33,115	77,888	93,741
Income from continuing operations before Minority interest	548	15,961	51,305	137,234	160,995
Minority interest	247	4,705	384	(49)	(569)
Income from continuing operations	301	11,256	50,921	137,283	161,564
Income from discontinued operations (net of tax expense of $679, $317, $601, $1,987 and $0, respectively)	1,175	2,628	2,941	1,803	
Net income	$ 1,476	$ 13,884	$ 53,862	$ 139,086	$ 161,564
Income from continuing operations per diluted share	$ 0.02	$ 0.37	$ 1.00	$ 2.02	$ 2.20

(1) 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. Although this sale does not represent a material disposition of assets relative to our total assets as presented in the accompanying balance sheets, the disposal group does 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 in accordance with SFAS No. 144, Accounting for the Impairment or

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Disposal of Long-Lived Assets. We revised our financial statements, pursuant to SFAS No. 144, and reclassified the assets and liabilities of the disposal group 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 from discontinued operations, net of tax, for each of the accompanying statements of operations. We ceased depreciating the assets of this disposal group in September 2006 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 $0.1 million. The disposal group was sold on October 31, 2006, resulting in a loss on the sale of $0.6 million.

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

(3) We paid a dividend to our stockholders as of September 12, 2005 in conjunction with the Combination. Our current debt obligations restrict us from paying dividends on our common stock. For a further discussion, see Item 5. Market for Registrant s Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities Dividends included elsewhere in this Annual Report.

(4) We recorded an impairment loss associated with goodwill in Canada during the year ended December 31, 2007. 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.

	As of December 31,				
	2003	2004	2005	2006	2007
	(In thousands)				
Other Financial Data:					
EBITDA(5)	$ 11,540	$ 55,263	$ 157,390	$ 333,959	$ 464,828
Cash flows from operating activities	13,965	34,622	76,427	187,743	338,560
Cash flows from financing activities	55,281	157,630	112,139	471,376	66,643
Cash flows from investing activities	(66,214)	(186,776)	(188,358)	(650,863)	(408,795)
Capital expenditures:					
Acquisitions, net of cash acquired(6)	54,798	139,362	67,689	369,606	50,406
Property, plant and equipment	11,084	46,904	127,215	303,922	372,554

	For the Year Ended December 31,				
	2003	2004	2005	2006	2007
	(In thousands)				
Balance Sheet Data:					
Cash and cash equivalents	$ 6,094	$ 11,547	$ 11,405	$ 19,874	$ 13,681
Net property, plant and equipment	94,666	234,450	383,707	771,703	1,034,695
Goodwill	54,957	140,903	293,651	552,671	560,488
Total assets	206,066	515,153	937,653	1,740,324	2,054,759

Long-term debt, excluding current portion	50,144	169,178	509,981	750,577	825,987
Total stockholders equity	97,956	172,080	250,761	735,221	930,323

(5) EBITDA consists of net income from continuing operations before interest expense, taxes, depreciation and amortization, minority interest and impairment loss. See Non-GAAP Financial Measures. 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 EBITDA. In addition, we use EBITDA in evaluating acquisition targets. Management also believes that EBITDA is a useful tool for measuring our ability to meet our future debt service, capital expenditures and working capital requirements, and EBITDA is commonly used by us and our investors to measure our ability to service indebtedness. EBITDA is not a substitute for the GAAP measures of

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earnings or of 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 minority interest. The following table reconciles EBITDA with our net income.

Reconciliation of EBITDA

	For the Year Ended December 31,				
	2003	**2004**	**2005**	**2006**	**2007**
			(In thousands)		
Net income	$ 1,476	$ 13,884	$ 53,862	$ 139,086	$ 161,564
Plus: interest expense, net	2,683	7,471	24,460	39,372	61,037
Plus: tax expense	827	10,504	33,115	77,888	93,741
Plus: depreciation and amortization	7,482	21,327	48,510	79,465	135,961
Plus: minority interest	247	4,705	384	(49)	(569)
Plus: impairment loss					13,094
Minus: income from discontinued operations (net of tax expense of $679, $317, $601, $1,987 and $0, respectively)	1,175	2,628	2,941	1,803	
EBITDA	$ 11,540	$ 55,263	$ 157,390	$ 333,959	$ 464,828

(6) 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.

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. 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 update publicly 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 express 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 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, Kansas, western Canada, Mexico and Southeast Asia.

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On September 12, 2005, we completed the Combination (see Item 1. Business The Combination) of Complete Energy Services, Inc. (CES), Integrated Production Services, Inc. (IPS) and I.E. Miller Services, Inc. (IEM) pursuant to which the CES and IEM shareholders exchanged all of their common stock for common stock of IPS. The Combination was accounted for using the continuity of interests method of accounting, which yields results similar to the pooling of interest method. Subsequent to the Combination, IPS changed its name to Complete Production Services, Inc.

On April 26, 2006, we completed our initial public offering and our common stock is currently trading on the New York Stock Exchange under the symbol CPX. The total offering amount was approximately $718 million, consisting of approximately $312 million in a primary offering (less underwriters fees and discounts) and approximately $406 million in a secondary offering by selling stockholders.

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. We also offer several proprietary services and products that we believe create significant value for our customers.
>
> *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, specialized rig logistics and site preparation throughout our service area. Our drilling rigs currently operate exclusively in and around the Barnett Shale region of north Texas.

Product Sales. Through our product sales segment, we provide a variety of equipment used by oil and gas companies throughout the lifecycle of their wells. We sell a full range of oilfield supplies, as well as tubular goods, throughout the United States (north Texas, Louisiana, Arkansas, Oklahoma and the Rocky Mountains), primarily through our supply stores. We also sell products through our Southeast Asia business and through agents in markets outside of North America.

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. 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 factor influencing demand for our services and products is the level of drilling and workover activity of our customers, 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

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service rig activity, as measured by Baker Hughes Incorporated (BHI) and the Weatherford/AESC Service Rig Count for Active Rigs , respectively, and historical commodity prices as provided by Bloomberg:

AVERAGE RIG COUNTS

	Year Ended 12/31/02	Year Ended 12/31/03	Year Ended 12/31/04	Year Ended 12/31/05	Year Ended 12/31/06	Year Ended 12/31/07
BHI Rotary Rig Count:						
U.S. Land	717	924	1,095	1,290	1,559	1,695
U.S. Offshore	113	108	97	93	90	73
Total U.S.	830	1,032	1,192	1,383	1,649	1,768
Canada	263	372	365	455	471	343
Total North America	1,093	1,404	1,557	1,838	2,120	2,111

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

	Year Ended 12/31/02	Year Ended 12/31/03	Year Ended 12/31/04	Year Ended 12/31/05	Year Ended 12/31/06	Year Ended 12/31/07
Weatherford/AESC Service Rig Count (Active Rigs):						
United States	1,830	1,967	2,064	2,222	2,364	2,388
Canada	627	710	755	795	779	596
Total	2,457	2,677	2,819	3,017	3,143	2,984

Source: Weatherford/AESC Service Rig Count for Active Rigs

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)
1/1/99 12/31/99	$ 2.27	$ 19.30

1/1/00	12/31/00	4.31	30.37
1/1/01	12/31/01	3.97	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

Source: Bloomberg NYMEX prices.

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. We evaluate the utilization of our assets as a measure of operating performance. This utilization can be impacted by these and other external and internal factors.
See Item 1A. Risk Factors.

We generally charge for our services on a dayrate basis. Depending on the specific service, a dayrate may include one or more of these components: (1) a set-up charge, (2) an hourly service rate based on equipment and labor, (3) an equipment rental charge, (4) a consumables charge and (5) 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 are generated through our supply stores, our Southeast Asian business and through wholesale distributors, using a purchase order process and a pre-determined price book.

Outlook

Our growth strategy includes a focus on internal growth in our current basins and seek to maximize our equipment utilization, add additional like-kind equipment and expand service and product offerings. In addition, we identify new basins in which to replicate this approach. We also augment our internal growth through strategic acquisitions.

Internal Capital Investment. Our internal expansion activities generally consist of adding equipment and qualified personnel in locations where we have established a presence. We expect to grow our operations in each 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 $803.7 million in equipment additions over the three-year period ended December 31, 2007, which included $621.4 million for the completion and production services segment, $156.7 million for the drilling services segment, $18.1 million for the product sales segment and $7.5 million related to general corporate operations. We expect to invest approximately $150.0 million in capital equipment during the year ended December 31, 2008.

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 period to period. Accordingly, comparisons of revenue and operating results are not necessarily comparable and should not be relied upon as indications of future performance. We have invested an aggregate of $601.1 million in acquisitions over the three-year period ended December 31, 2007 excluding the acquisition of minority interests in CES and IEM resulting from the Combination. Of this amount, we invested an aggregate of $49.7 million to acquire 7 businesses during 2007 and $449.9 million to acquire 16 companies during 2006, including the value of equity issued and debt assumed in conjunction with those 2006 acquisitions, a portion of which was associated with earn-out agreements for 2005 and 2004 acquisitions. See Significant Acquisitions.

Natural gas prices have declined from historical highs in 2006 and rotary rig counts may have peaked in 2007 and have recently begun to decline, particularly in Canada. This trend could be the result of a number of macro-economic factors, such as a perceived excess supply of natural gas, lower demand for oil and gas or the use of alternate fuels, market expectations of weather conditions and the utilization of heating fuels, the cyclical nature of the oil and gas industry and other general market conditions for the U.S. economy. Although we cannot determine the impact that lower commodity prices and rotary rig counts may have on our business or whether such declines will be long-term, we believe that North American oilfield activity and the overall long-term outlook for our business remains favorable from an activity perspective, especially in the basins in which we operate, including the Piceance, Greater Green River and DJ basins in the Rocky Mountain region, the Barnett Shale of north Texas and Anadarko and Arkoma basins in the Mid-continent region, including the Fayetteville Shale in Arkansas and the Woodford Shale in Oklahoma. We believe that the fundamentals in these markets are favorable, but we have begun to experience less favorable pricing and lower utilization for some service offerings in certain areas in which we operate, which may be due in part to an increase in equipment placed into service in the region by our competitors, a slow-down of activity by our customers due to limited pipeline take-away capacity, particularly in southwest Wyoming, or a belief that current inventory levels of natural gas may exceed expected demand for the short-term.

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During 2007, activity levels in Canada have declined significantly compared to recent years. This decline may be partially the result of an excess of natural gas currently in storage in Canada and an overall reluctance of major oil and gas companies to invest as heavily in drilling and exploration efforts due to perceived unfavorable tax treatment related to royalty arrangements and other governmental restrictions. Although we believe that this market will recover in future periods, we cannot determine when this recovery will occur or if such recovery will result in favorable operating results which are comparable to the levels achieved in prior years. Based upon our assessment of our expected future cash flows from operations in Canada, we recorded a non-cash impairment loss related to the write-down of goodwill at our Canadian subsidiary during the fourth quarter of 2007, which resulted in a reduction of operating income and net income by $13.1 million, as we did not receive a tax benefit associated with this impairment loss. We still remain invested in the Canadian market and believe the fundamentals are such to encourage a recovery in this market in the future.

Our business continues to be impacted by seasonality and inclement weather conditions. Our completion and production services business in Canada experienced a slower than expected recovery from the effects of the normal second quarter Canadian break-up. Our operations in south Texas, Mexico and the Mid-continent region were also impacted by Gulf of Mexico tropical weather systems and inclement weather during 2007.

As drilling activity has trended upwards the last few years and oilfield activity levels have increased, we, and many of our competitors, have invested in new equipment, some of which requires long lead times to manufacture. As more of this equipment is placed into service, there could be excess capacity in the industry, which we believe may have negatively impacted our utilization rates and pricing for certain service offerings during the latter half of 2007, and may continue to impact our operations in future periods. In addition, as new equipment enters the market, we must compete for employees to crew the equipment, which puts inflationary pressure on labor costs, and higher oil and gas commodity prices have resulted in higher fuel costs to operate our equipment. Our equipment fleet is relatively new, as we made significant investments in new equipment over the past two years and expect to continue to invest in equipment to the extent that we expect demand to remain high for certain of our service offerings, in particular our well service and coiled tubing services. We continue to monitor our equipment utilization and poll our customers to assess demand levels. As more equipment enters the marketplace, we believe our customers will increasingly rely upon service providers with local knowledge and expertise, which we believe we have and which constitutes a fundamental aspect of our strategic acquisition growth strategy.

Significant Acquisitions

During 2007, we acquired substantially all the assets or all of the equity interests in six oilfield service companies, and the remaining 50% interest in our Canadian joint venture, for $49.7 million in cash, resulting in goodwill of approximately $19.4 million. Several of these acquisitions are subject to final working capital adjustments.

On January 4, 2007, we acquired substantially all of the assets of a company located in LaSalle, Colorado, which provides frac tank rental and fresh water hauling services to customers in the Wattenburg Field of the DJ Basin, which supplements our fluid handling and rental business in the Rocky Mountain region.

On February 28, 2007, we acquired substantially all of the assets of a company located in Greeley, Colorado, which provides fluid handling and fresh frac water heating services to customers in the Wattenburg Field of the DJ Basin, which also supplements our fluid handling business in the Rocky Mountain region.

On April 1, 2007, we acquired substantially all of the assets of a company located in Borger, Texas, which provides fluid handling and disposal services to customers in the Texas panhandle. We believe this acquisition complements certain operations that we acquired in 2006 within the Texas panhandle area and broadens our ability to provide fluid handling and disposal services throughout the Mid-continent region.

On June 8, 2007, we acquired all the membership interests in a business located in Rangely, Colorado, which provides rig workover and roustabout services to customers in the Rangely Weber Sand Unit and northern Piceance Basin area. This acquisition expands our geographic reach in the northern Piceance Basin, expands our workover rig capabilities and provides a beneficial customer relationship.

On October 18, 2007, we acquired all of the outstanding common stock of a company located in Kilgore, Texas, which provides remedial cement and acid services used in pressure pumping operations to customers throughout the east Texas region. This acquisition supplements our pressure pumping business and expands our presence in east Texas.

On November 30, 2007, we acquired substantially all of the assets of a company located in Greeley, Colorado, which is an e-line service provider to customers in the Wattenberg Field of the DJ Basin. This acquisition supplements our completion and production services business in the Rocky Mountain region.

On December 31, 2007, we acquired the remaining 50% interest in our joint venture in Canada for approx. $1.6 million. This transaction resulted in a decrease in goodwill of approx. $0.6 million, as the amount paid was less than the minority interest liability recorded related to this operation. This company provides optimization services in the Canadian market.

We do not consider our acquisitions in 2007 as significant to our overall financial position at December 31, 2007 or our results of operations for the year ended December 31, 2007, individually or in the aggregate.

The following entities were acquired in 2006 and 2005 and are deemed to be our most significant acquisitions in recent years:

Parchman Energy Group, Inc. On February 11, 2005, we acquired Parchman Energy Group, Inc. (Parchman) for $9.8 million in cash, the issuance of common stock totaling $16.9 million, the issuance of a subordinated note totaling $5.0 million and the potential issuance of 1,000,000 shares of our common stock based upon certain operating results. All 1,000,000 such shares of our common stock were issued in the first quarter of 2006. In addition, we granted 344,664 shares of non-vested restricted stock to former Parchman employees. These restricted shares were fully vested as of December 31, 2007, or were forfeited. Parchman performs intervention services and downhole services including coiled tubing, production testing and wireline services, and operates from locations in Texas, Louisiana and Mexico. We recorded $20.3 million of goodwill related to this acquisition in 2005. We recognized additional goodwill associated with the issuance of these 1,000,000 shares in the first quarter of 2006 in an amount equal to the fair value of the shares, or $23.5 million.

Big Mac. On November 1, 2005, we acquired all of the outstanding equity interests of the Big Mac group of companies (Big Mac Transports, LLC, Big Mac Tank Trucks, LLC and Fugo Services, LLC) for $40.8 million in cash. The Big Mac group of companies (Big Mac) is based in McAlester, Oklahoma, and provides fluid handling services primarily to customers in eastern Oklahoma and western Arkansas. Big Mac s principal assets consist of rolling stock and frac tanks. A final purchase price post-closing adjustment for actual working capital and reimbursable capital expenditures was recorded during 2006 which resulted in a reduction of goodwill of approximately $0.5 million. We recorded $23.7 million of goodwill in connection with this acquisition. We have included the operating results of Big Mac in the completion and production services business segment from the date of acquisition. This acquisition provided a platform to enter the eastern Oklahoma market and new Fayetteville Shale play in Arkansas.

Arkoma. On June 30, 2006, we acquired certain operating assets of J&M Rental Tool, Inc dba Arkoma Machine & Fishing Tools, Arkoma Machine Shop, Inc. and N&M Supply, LLC, collectively referred to as Arkoma , a provider of rental tools, machining and fishing services in the Fayetteville Shale and Arkoma Basin, located in Ft. Smith, Arkansas. We paid $18.0 million in cash to acquire Arkoma and recorded goodwill totaling $9.0 million, which has been allocated entirely to the completion and production services business segment. This acquisition provided a platform to further expand our presence in the Fayetteville Shale and

Arkoma Basin and supplements our completion and production services business in that region.

Turner. On July 28, 2006, we acquired all of the outstanding equity interests of the Turner group of companies (Turner Energy Services, LLC, Turner Energy SWD, LLC, T. & J. Energy, LLC, T. & J. SWD, LLC and Loyd Jones Well Service, LLC) for $54.3 million in cash, after a final working capital adjustment. The Turner Group of Companies (Turner) is based in the Texas panhandle in Canadian, Texas, and owns a fleet of well service rigs, and provides other wellsite services such as fishing, equipment rental, fluid handling and salt water disposal services. We recorded goodwill totaling $16.0 million associated with this

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purchase. We have included the accounts of Turner in our completion and production services business segment from the date of acquisition. We believe this acquisition supplements our completion and production services business in the Mid-continent region.

Pinnacle. On August 1, 2006, we acquired substantially all of the assets of Pinnacle Drilling Co., L.L.C. (Pinnacle), a drilling company located in Tolar, Texas, for $32.8 million in cash, which includes $1.1 million related to equipment refurbishment. Pinnacle operates three drilling rigs, two in the Barnett Shale region of north Texas and one in east Texas. We recorded goodwill totaling $1.0 million associated with this purchase. We finalized our purchase price allocation for Pinnacle during 2007 and received $0.6 million from the seller related to pre-acquisition contingencies which resulted in a reduction of goodwill of $0.6 million. We have included the accounts of Pinnacle in our drilling services business segment from the date of acquisition. This acquisition increases our presence in the Barnett Shale of north Texas and the Bossier Trend of east Texas and expands our capacity to drill deep and horizontal wells, which are sought by our customers in this region.

Femco. On October 19, 2006, we acquired substantially all of the assets of Femco Services, Inc., R&S Propane, Inc. and Webb Dozer Service, Inc. (collectively, Femco), a group of companies located in Lindsay, Oklahoma for $36.0 million in cash. Femco provides fluid handling, frac tank rental, propane distribution and fluid disposal services throughout southern central Oklahoma. We recorded goodwill totaling $11.2 million associated with this purchase. We have included the accounts of Femco in our completion and production services business segment from the date of acquisition. We believe this acquisition expands our presence in the Fayetteville Shale and enhances our completion and production services business in the Mid-continent region.

Pumpco. On November 8, 2006, we acquired all the outstanding equity interests of Pumpco, a company located in Gainesville, Texas for approximately $144.6 million in cash, net of cash acquired, and 1,010,566 shares of our common stock. We also assumed approximately $30.3 million of debt outstanding under Pumpco s existing credit facility. Pumpco provides pressure pumping, stimulation and cementing services used in the development and completion of gas and oil wells in the Barnett Shale play of north Texas. We recorded goodwill totaling $148.6 million associated with this acquisition. The purchase price allocation for Pumpco was finalized in 2007 which resulted in a reclassification of $2.0 million from goodwill to other intangible assets, and a reduction of goodwill of $3.1 million related the deferred tax liabilities acquired which were deemed unnecessary based on our 2006 tax return filings in 2007. We have included the accounts of Pumpco in our completion and production services business from the date of acquisition. This acquisition expanded our presence in the Barnett Shale and expands the service offerings of our completion and product services business to include pressure pumping.

In addition, we completed several other smaller acquisitions, each of which has contributed to the expansion of our business into new geographic regions or enhanced our service and product offerings.

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, with the exception of the Combination, which was accounted for using the continuity of interests accounting method. Results of operations related to each of the acquired companies have been included in our combined operations as of the date of acquisition.

On October 31, 2006, we completed the sale of the disposal group which included certain manufacturing and production enhancement product operations of a subsidiary located in Alberta, Canada, as well as operations in south Texas, for approximately $19.3 million in cash, with an additional amount subject to a working capital adjustment, and a $2.0 million Canadian dollar denominated note which matures on October 31, 2009 and accrues interest at a specified Canadian bank prime rate plus 1.50% per annum. We sold this disposal group to Paintearth Energy Services, Inc., an oilfield service company located in Calgary, Alberta, Canada, that employs two of our former employees as key managers. The carrying value of the related net assets was $21.7 million on October 31, 2006. We recorded a loss on the sale of this disposal group totaling approximately $0.6 million, which included a transaction gain associated with the release of cumulative translation adjustment associated with this business, and a $1.0 million charge to expense related to capital taxes in Canada. The sales agreement allowed Paintearth Energy

Services, Inc. to use our subsidiary s trade name for a period of 120 days from November 1, 2006 through February 28, 2007.

Marketing 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.

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%, 7% and 9% of total revenues from continuing operations during the years ended December 31, 2007, 2006 and 2005, respectively.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with 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 1 of the notes to the consolidated financial statements contained elsewhere in this Annual Report on Form 10-K. 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.

Continuity of Interests Accounting

We applied the provisions of Statement of Financial Accounting Standards (SFAS) No. 141, Business Combinations to account for the formation of Complete. SFAS No. 141 permits us to account for the combination of several predecessor companies using a method similar to a pooling of interests if each is controlled by a common stockholder. In connection with the Combination, we paid a dividend to our stockholders of $2.62 per share and adjusted the number of shares subject to, and exercise price of, outstanding stock options and restricted shares in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 44, Accounting for Certain Transactions Involving Stock Compensation, an Interpretation of Accounting Principles Board (APB) Opinion No. 25. On September 12, 2005, we completed the transaction, pursuant to which CES and IEM stockholders exchanged all of their common stock for common stock of IPS. CES stockholders received 19.704 shares of IPS common stock for each share of CES common stock, and IEM stockholders received 19.410 shares of IPS common stock for each share of IEM common stock. In connection with the Combination, IPS changed its name to Complete Production Services, Inc. We acquired the interests of the minority stockholders in these predecessor companies as of the date of the consummation and accounted for these transactions using the purchase method of accounting, resulting in goodwill of $93.8 million, which represented the excess of the purchase price over the carrying value of the net assets acquired.

Application of SFAS No. 141 is required under U.S. GAAP when entities under common control are combined.

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 and record revenues as products are sold. We did not record material adjustments resulting from revenue recognition issues for the years ended December 31, 2007, 2006 and 2005.

Impairment of Long-Lived Assets

We evaluate potential impairment of long-lived assets and intangibles, excluding goodwill and other intangible assets without defined services lives, when indicators of impairment are present, as defined in SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. 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 apply the provisions of SFAS No. 142, Goodwill and Other Intangible Assets, which requires 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 consistent with that described in SFAS No. 141. 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, 2007, 2006, and 2005. For the years ended December 31, 2006 and 2005, management determined that goodwill was not impaired. However, in 2007, management prepared a discounted cash flow analysis to determine the fair market value of each reportable unit as of the testing date, October 1, 2007. 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 in Canada was impaired. In accordance with SFAS No. 142, management performed a step-two analysis to calculate the amount by which the carrying value of this reporting unit exceeded the projected fair market value of such unit as of October 1, 2007. As a result, management recorded an impairment charge which reduced goodwill in Canada by $13.4 million. In calculating this impairment charge, management made assumptions about future earnings in Canada, which may differ from actual future earnings for this reportable unit, which could result in a future impairment charge. In addition, a significant decline in expected future cash flow as a result of lower revenues, an overall decline in market conditions in Canada or a lower-than-expected recovery of the Canadian market in future years, could result in an impairment charge. A 10% impairment of total goodwill at December 31, 2007 would have decreased our operating income by $56.0 million for the year then ended.

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 non-vested restricted stock. We adopted SFAS No. 123R, Share-Based Payment, on January 1, 2006, which impacted our accounting treatment of employee stock options. As required by SFAS No. 123R, we continue to account for stock-based compensation for grants made prior to September 30, 2005, the date of our initial filing with the SEC, using the minimum value method prescribed by APB No. 25, 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. However, for grants of stock-based compensation between October 1, 2005 and December 31, 2005 (prior to adoption of SFAS No. 123R), we have utilized the modified prospective transition method to record expense associated with these options. Under this transition method, we did not record compensation expense associated with these stock option grants during the period October 1, 2005 through December 31, 2005, but will provide pro forma disclosure of this expense as appropriate. However, we will recognize expense related to these grants over the remaining vesting period, based upon a calculated fair value. For grants of stock-based compensation on or after January 1, 2006, we apply the prospective transition method under SFAS No. 123R, whereby 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 non-vested restricted stock which has been granted to certain of our directors, officers and employees. In accordance with SFAS No. 123R, 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.

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 years ended on or before December 31, 2005, we determined the value of our stock options by applying the minimum value method permitted by APB No. 25 and, in connection with estimating compensation expense that would be required to be recognized under SFAS No. 123, Accounting for Stock-Based Compensation, we used a Black-Scholes model including assumptions for expected term (ranging from 3 to 4.5 years as of December 31, 2005), risk- free rate (based upon published rates for U.S. Treasury notes with a similar term), zero dividend rate and a volatility rate of zero. For the years ended December 31, 2007 and 2006, we applied a Black-Scholes model with similar assumptions, except we estimated our stock volatility by examining the volatility rates of several peer companies, we estimated a forfeiture rate based upon our historical experience and we estimated the expected term of the options using a probability analysis. For the years ended December 31, 2007 and 2006, we have recorded compensation expense totaling $4.4 million and $1.8 million, respectively, related to our stock option grants and $3.1 million and $2.8 million, respectively, related to our non-vested restricted stock.

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

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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 has been less than 1% of sales for the years ended December 31, 2007, 2006 and 2005. If bad debt expense had increased by 1% of sales for the years ended December 31, 2007, 2006 and 2005, net income would have declined by $10.8 million, $7.7 million and $4.4 million, respectively. Our obsolescence and other inventory reserves as of December 31, 2007, 2006 and 2005 have ranged from 4% to 6%. Our obsolescence and other inventory reserves were approximately 4% of inventory at December 31, 2007 and 2006. A 1% increase in inventory reserves, from 4% to 5%, at December 31, 2007 would have decreased net income by $0.4 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.

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. There have been no significant impairment charges related to our long-term assets during the years ended December 31, 2007, 2006 and 2005. Depreciation and amortization expense for the years ended December 31, 2007 and 2006 represented 16% and 15% of the average depreciable asset base for the respective years. An increase in depreciation relative to the depreciable base of 1%, from 15% to 16%, would have reduced net income by approximately $5.4 million for the year ended December 31, 2007.

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 material losses in the future. At December 31, 2007, we accrued $3.7 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, 2007 by $0.2 million, respectively.

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 using SFAS No. 109,

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Accounting for Income Taxes. Under SFAS No. 109, we 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, SFAS No. 109 requires us to record a valuation allowance for any net deferred income tax assets which we believe are likely to not be used through future operations. As of December 31, 2007, 2006 and 2005, 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, 2007, we did not provide deferred U.S. income taxes on approximately $19.1 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 Financial Interpretation No. 48 (FIN 48), which provides guidance to account for uncertain tax positions. During 2007, we performed an evaluation of our tax positions pursuant to Financial Interpretation No. 48 (FIN 48) and determined that this pronouncement did not have a material impact on our financial position, results of operations and cash flows.

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 $8.0 million at December 31, 2007, against which we recorded a valuation allowance of $0.3 million, leaving a net deferred tax asset of $7.7 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 SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. SFAS No. 144 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.

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Results of Operations for the Years Ended December 31, 2007 and 2006

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 12/31/07	Year Ended 12/31/06	Change 2007/ 2006	Percent Change 2007/ 2006
	(In thousands)			
Revenue:				
Completion and production services	$ 1,262,100	$ 873,493	$ 388,607	44%
Drilling services	240,377	215,255	25,122	12%
Product sales	152,760	123,676	29,084	24%
Total	$ 1,655,237	$ 1,212,424	$ 442,813	37%
EBITDA:				
Completion and production services	$ 404,893	$ 257,630	$ 147,263	57%
Drilling services	69,628	78,543	(8,915)	(11)%
Product sales	18,443	18,708	(265)	(1)%
Corporate	(28,136)	(20,922)	(7,214)	34%
Total	$ 464,828	$ 333,959	$ 130,869	39%

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

EBITDA consists of net income from continuing operations before interest expense, taxes, depreciation and amortization, minority interest and impairment loss. EBITDA is a non-cash measure of performance. We use EBITDA as the primary internal management measure for evaluating performance and allocating additional resources. See the discussion of EBITDA at Note 3 under Item 6 (Selected Financial Data) of this Annual Report. The following table reconciles EBITDA for the years ended December 31, 2007 and 2006 to the most comparable GAAP measure, operating income (loss).

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

Year Ended December 31, 2007	Completion and Production Services	Drilling Services	Product Sales	Corporate	Total
EBITDA, as defined	$ 404,893	$ 69,628	$ 18,443	$ (28,136)	$ 464,828
Depreciation and amortization	$ 114,139	$ 17,023	$ 2,918	$ 1,881	$ 135,961
Impairment loss	$ 13,094	$	$	$	$ 13,094

Operating income (loss)	$	277,660	$	52,605	$	15,525	$	(30,017)	$	315,773
Year Ended December 31, 2006										
EBITDA, as defined	$	257,630	$	78,543	$	18,708	$	(20,922)	$	333,959
Depreciation and amortization	$	65,317	$	10,599	$	1,943	$	1,606	$	79,465
Write-off of deferred costs	$		$		$		$	(170)	$	(170)
Operating income (loss)	$	192,313	$	67,944	$	16,765	$	(22,358)	$	254,664

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

Year Ended December 31, 2007 Compared to the Year ended December 31, 2006

Revenue

Revenue for the year ended December 31, 2007 increased by $442.8 million, or 37%, to $1,655.2 million from $1,212.4 million for the year ended December 31, 2006. This increase by segment was as follows:

Completion and Production Services. Segment revenue increased $388.6 million, or 44%, primarily due to: (1) higher activity levels in the U.S. and Mexico; (2) an increase in revenues earned as a result of additional capital investments in the coiled tubing, well servicing, pressure pumping, rental and fluid-handling businesses in 2007, as well as the benefit of a full-year of operations for equipment placed into service throughout 2006; (3) investment in acquisitions during 2006, each of which provided incremental revenues for 2007 compared to 2006; and (4) a series of acquisitions during the year ended December 31, 2007 which contributed to the overall 2007 results. These favorable results were partially offset by a decline in the general activity level of the oil and gas industry in Canada throughout 2007. We began to experience some pricing pressures in certain service offerings during the latter half of 2007.

Drilling Services. Segment revenue increased $25.1 million, or 12%, for the year, primarily due to additional capital invested in contract drilling and our drilling logistics businesses during 2006 and into 2007, somewhat offset by lower pricing and lower utilization of our equipment in 2007 compared to 2006, due primarily to an increase in new equipment placed into service by our competitors in the markets that we serve.

Product Sales. Segment revenue increased $29.1 million, or 24%, for the year, fueled primarily by increased product sales and equipment refurbishment attributable to our business in Southeast Asia, as well as an increase in sales of tubular goods through our supply stores.

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 $269.3 million, or 38%, to $980.3 million for the year ended December 31, 2007 from $711.0 million for the year ended December 31, 2006. The following table summarizes service and product expenses as a percentage of revenues for the years ended December 31, 2007 and 2006:

Service and Product Expenses as a Percentage of Revenue

	Years Ended		
Segment:	**12/31/07**	**12/31/06**	**Change**
Completion and Production services	57%	58%	(1)%
Drilling services	61%	54%	7%
Product sales	76%	71%	5%
Total	59%	59%	

Service and product expenses as a percentage of revenue were consistent for the years ended December 31, 2007 and 2006. However, margins by business segment were impacted by acquisitions, pricing and utilization.

Completion and Production Services. The decline in service and product expenses as a percentage of revenue for this business segment reflects: (1) a full-year s benefit in 2007 of capital invested throughout 2006, with additional equipment placed into service during 2007 and (2) the benefit of a full-year of margin contribution from our pressure pumping business in 2007 compared to only two-months contribution in 2006 due to timing of the acquisition. We experienced favorable margins in 2007 compared to 2006 for our well service, coiled tubing, fluid handling and rental businesses. However, in late 2007, we began to experience lower pricing for certain of these services in some of our operating regions, as well as a general decline in

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activity levels in Canada which impacted our operating margins, reducing our overall margin improvements to only 1% year-over-year. In addition, we experienced higher labor and fuel costs which partially offset the incremental margin contribution of our completion and production services businesses during 2007 compared to 2006.

Drilling Services. The increase in service and product expenses as a percentage of revenue for this business segment represented a decline in margin during 2007 compared to 2006 due to: (1) lower pricing for our contract drilling and drilling logistics businesses, and (2) lower utilization of our equipment, specifically impacting our drilling rigs business, due to downtime associated with maintenance, and more market competition, as our competitors deployed additional rigs into the markets we serve. In addition, we incurred costs associated with relocating a portion of our rig logistics business to areas with more favorable market conditions.

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 through our supply stores, including an increase in sales of relatively lower-margin tubular goods in 2007 compared to 2006, and the timing of equipment sales and refurbishment associated with our Southeast Asian operations.

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 increased $42.8 million, or 26%, for the year ended December 31, 2007 to $210.1 million from $167.3 million during the year ended December 31, 2006. These expense increases included: (1) costs associated with businesses acquired in 2007, including additional employee headcount, property rental expense and insurance expense; (2) costs associated with 2006 acquisitions which provided a full-year of selling, general and administrative expense for 2007; (3) consulting costs associated with our Sarbanes-Oxley compliance documentation and testing, outside accounting, tax and legal services and information technology initiatives; (4) incremental costs of approximately $3.2 million related to stock-based compensation in 2007 compared to 2006; and (5) a charge of approximately $1.4 million associated with the cost-sharing provision of a general liability insurance policy. As a percentage of revenues, selling, general and administrative expense declined to 13% for the year ended December 31, 2007 compared to 14% for the year ended December 31, 2006.

Depreciation and Amortization

Depreciation and amortization expense increased $56.5 million, or 71%, to $136.0 million for the year ended December 31, 2007 from $79.5 million for the year ended December 31, 2006. The increase in depreciation and amortization expense was the result of equipment placed into service in 2007, a portion of which was purchased in 2006 and throughout 2007. Capital expenditures for equipment in 2007 totaled $372.6 million. In addition, we recorded depreciation and amortization expense related to businesses acquired in 2006 and 2007, as well as assets purchased and placed into service throughout 2006, which contributed a full year of depreciation expense in 2007 compared to a partial year of depreciation expense in 2006. As a percentage of revenue, depreciation and amortization expense increased to 8% for the year ended December 31, 2007 compared to 7% for the year ended December 31, 2006.

Interest Expense

Interest expense was $62.7 million and $40.8 million for the years ended December 31, 2007 and 2006, respectively. The increase in interest expense was attributable to an increase in the average amount of debt outstanding, including amounts borrowed to fund acquisitions, capital expenditures, our semi-annual interest payments associated with the 8% senior notes and our quarterly tax payments. In addition, during December 2006, we issued our 8% senior notes and used the proceeds to retire all outstanding borrowings under the term loan portion of our credit facility. These senior notes required interest at higher fixed interest rates compared to the lower variable rates on the previously outstanding term loan facility. The weighted-average interest rate of borrowings outstanding at December 31, 2007 and 2006 was approximately 7.69% and 7.84%, respectively.

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Interest Income

Interest income was $1.6 million for the year ended December 31, 2007. This interest income was earned primarily on excess cash invested in overnight securities throughout 2007.

Impairment Loss

We recorded an impairment loss of $13.1 million related to the write-down of goodwill associated with our Canadian operations during 2007 based upon a discounted cash flow analysis of expected future earnings associated with this business.

Taxes

Tax expense 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.

Tax expense was 36.8% and 36.2% of pretax income for the years ended December 31, 2007 and 2006, respectively. The effective tax rate for 2007 was impacted by the impairment loss of $13.1 million in Canada, which was not deductible for tax purposes. Excluding the impact of the impairment loss, the effective tax rate for 2007 would have been 35.0%. The decline in the effective tax rate in 2007, as adjusted, compared to 2006, was due to lower state tax rates, lower income tax rates in Canada, return to actual adjustments in 2007 and the incremental benefit of the domestic production activities deduction.

Minority Interest

Minority interest was comprised entirely of an ownership interest by an unrelated third party in the assets of Premier Integrated Technologies, Inc. (Premier), a company that we acquired on January 1, 2005. We have consolidated Premier in our accounts since the date of acquisition and record minority interest to reflect the ownership held by this third party. On December 31, 2007, we acquired the remaining 50% interest in this company, so that it is a wholly-owned subsidiary of Complete at December 31, 2007.

Results of Operations for the Years Ended December 31, 2006 and 2005

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 12/31/06	Year Ended 12/31/05	Change 2006/ 2005	Percent Change 2006/ 2005
		(In thousands)		
Revenue:				
Completion and production services	$ 873,493	$ 510,304	$ 363,189	71%
Drilling services	215,255	129,117	86,138	67%
Product sales	123,676	80,768	42,908	53%
Total	$ 1,212,424	$ 720,189	$ 492,235	68%

EBITDA:				
Completion and production services	$ 257,630	$ 114,033	$ 143,597	126%
Drilling services	78,543	42,336	36,207	86%
Product sales	18,708	12,634	6,074	48%
Corporate	(20,922)	(11,613)	(9,309)	80%
Total	$ 333,959	$ 157,390	$ 176,569	112%

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

EBITDA consists of net income from continuing operations before interest expense, taxes, depreciation and amortization, minority interest and impairment loss. EBITDA is a non-cash measure of performance. We use EBITDA as the primary internal management measure for evaluating performance and allocating additional resources. See the discussion of EBITDA at Note 3 under Item 6 (Selected Financial Data) of this Annual Report. The following table reconciles EBITDA for the years ended December 31, 2006 and 2005 to the most comparable GAAP measure, operating income (loss).

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

	Completion and Production Services	Drilling Services	Product Sales	Corporate	Total
Year Ended December 31, 2006					
EBITDA, as defined	$ 257,630	$ 78,543	$ 18,708	$ (20,922)	$ 333,959
Depreciation and amortization	$ 65,317	$ 10,599	$ 1,943	$ 1,606	$ 79,465
Write-off of deferred costs	$	$	$	$ (170)	$ (170)
Operating income (loss)	$ 192,313	$ 67,944	$ 16,765	$ (22,358)	$ 254,664
Year Ended December 31, 2005					
EBITDA, as defined	$ 114,033	$ 42,336	$ 12,634	$ (11,613)	$ 157,390
Depreciation and amortization	$ 40,149	$ 5,666	$ 1,250	$ 1,445	$ 48,510
Write-off of deferred costs	$	$	$	$ (3,315)	$ (3,315)
Operating income (loss)	$ 73,884	$ 36,670	$ 11,384	$ (9,743)	$ 112,195

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

Year Ended December 31, 2006 Compared to the Year ended December 31, 2005

Revenue

Revenue for the year ended December 31, 2006 increased by $492.2 million, or 68%, to $1,212.4 million from $720.2 million for the year ended December 31, 2005. This increase by segment was as follows:

Completion and Production Services. Segment revenue increased $363.2 million, or 71%, primarily due to: (1) higher activity levels; (2) an increase in revenues earned as a result of additional capital investment in the coiled tubing, well servicing, rental and fluid-handling businesses in 2006, as well as the benefit of a full-year of operations for equipment placed into service throughout 2005; (3) a favorable pricing environment for our services; (4) investment in acquisitions during 2005, each of which provided incremental revenues for 2006 compared to 2005; and (5) a series of acquisitions during the year ended December 31, 2006 which contributed to the overall 2006 results.

Drilling Services. Segment revenue increased $86.1 million, or 67%, for the year, primarily due to: (1) higher utilization of our drilling equipment; (2) more favorable pricing; (3) additional capital investment in our Barnett Shale-focused drilling business throughout 2006; (4) the acquisition of Pinnacle on August 1, 2006;

and (5) investment in drilling logistics equipment used throughout our service areas.

Product Sales. Segment revenue increased $42.9 million, or 53%, for the year, fueled by an incremental increase in supply store sales as a result of the acquisition of new supply stores in late 2005, and the opening of several other supply stores in 2005, as well as increased product sales in Southeast Asia. During the second quarter of 2006, we expanded our tubular equipment product offerings at our supply stores, which has contributed to increased sales in 2006 compared to 2005.

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 $260.2 million, or 58%, to $711.0 million for the year ended December 31, 2006 from $450.7 million for the year ended December 31, 2005. The following table summarizes service and product expenses as a percentage of revenues for the years ended December 31, 2006 and 2005:

Service and Product Expenses as a Percentage of Revenue

	Years Ended		
Segment:	**12/31/06**	**12/31/05**	**Change**
Completion and Production services	58%	63%	(5)%
Drilling services	54%	55%	(1)%
Product sales	71%	70%	1%
Total	59%	63%	(4)%

The decline in service and product expenses as a percentage of revenue reflects improved margins as a result of: (1) a favorable mix of services and products, (2) improved pricing for our services, as more revenue was earned in 2006 from higher margin services in the United States and (3) a general increase in customer demand for oil and gas services and products throughout 2006, offset partially by rising labor, fuel, insurance and equipment costs. We were able to obtain more favorable pricing for our completion and production services segment and drilling services segment for these periods as a result of higher customer demand for these services primarily in the Barnett Shale region of north Texas, and the impact of acquired businesses. Margins associated with our product sales business declined slightly compared to the respective period in 2005, due primarily to the product mix and costs associated with opening new supply stores.

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 increased $58.6 million, or 54%, for the year ended December 31, 2006 to $167.3 million from $108.8 million during the year ended December 31, 2005. These expense increases were primarily due to acquisitions, which provided additional headcount, property rental expense, insurance expense and other administrative costs, as well as additional expense for incentive compensation accruals based on earnings. In addition, as a result of the Combination, we employed additional senior officers and key members of management at our corporate office. Furthermore, we incurred consulting costs associated with information technology and Sarbanes-Oxley projects, additional outside accounting, tax and legal fees associated with audits of subsidiaries, tax compliance and legal matters, and recorded incremental costs of approximately $2.8 million related to stock-based compensation. As a percentage of revenues, selling, general and administrative expense declined to 14% for the year ended December 31, 2006 compared to 15% for the year ended December 31, 2005.

Depreciation and Amortization

Depreciation and amortization expense increased $31.0 million, or 64%, to $79.5 million for the year ended December 31, 2006 from $48.5 million for the year ended December 31, 2005. The increase in depreciation and amortization expense was the result of placing into service equipment that was purchased during 2006. Capital expenditures for equipment in 2006 totaled $303.9 million. In addition, we recorded depreciation and amortization expense related to businesses acquired in 2005 and assets purchased and placed into services throughout 2005, which contributed a full year of depreciation expense in 2006 compared to a partial year of depreciation expense in 2005, and we recorded depreciation and amortization associated with business acquisitions in 2006. As a percentage of revenue, depreciation and amortization expense decreased by less than 1% for the year ended December 31, 2006 compared to the year ended December 31, 2005.

Interest Expense

Interest expense was $40.8 million and $24.5 million for the years ended December 31, 2006 and 2005, respectively. The increase in interest expense was attributable to an increase in the average amount of debt outstanding, including amounts borrowed to fund the dividend paid in connection with the Combination, borrowings for investment in capital expenditures, and acquisitions. In December 2006, we retired all outstanding borrowings under the term loan portion of our credit facility with proceeds from the issuance of 8% senior notes. The weighted-average interest rate of borrowings outstanding at December 31, 2006 and 2005 was approximately 7.84% and 7.22%, respectively. The increase in the borrowing rate was due to higher average borrowings under variable interest rate facilities in 2006 compared to 2005, a higher fixed interest rate on our senior notes issued in December 2006 compared to the average variable interest rate on our facilities outstanding in 2005, and a general increase in LIBOR and the U.S. prime interest rate throughout this two-year period.

Interest Income

Interest income was $1.4 million for the year ended December 31, 2006. This interest income was primarily earned on cash invested in short-term municipal bond funds and similar investments. The cash was received as a portion of the net proceeds from our initial public offering in April 2006, and was utilized for the purchase of equipment, business acquisitions and other corporate purposes throughout the period from the date of the initial public offering through December 31, 2006.

Taxes

Tax expense 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.

Tax expense was 36.2% and 39.2% of pretax income for the years ended December 31, 2006 and 2005, respectively. The change in the effective tax rate in 2006 compared to 2005 reflects the composition of earnings in domestic versus foreign tax jurisdictions, the effect of state and provincial income taxes, the timing of the use of net operating loss carry forwards and the benefit of the recently enacted domestic production activities deduction. The effective rates for 2006 also reflect the benefit derived from tax-free and tax-advantaged interest income received during the year ended December 31, 2006.

Write-off of Deferred Financing Costs

The write-off of $3.3 million of deferred financing costs in 2005 represents the remaining unamortized debt issuance costs associated with a term loan and revolving credit facility that was retired at the time of the Combination and replaced with our new credit facility. In December 2006, we retired all outstanding borrowings under Pumpco s term loan facility, which was assumed at the date of acquisition, resulting in the write-off of the remaining unamortized debt issuance costs totaling $0.2 million.

Minority Interest

Minority interest was comprised entirely of an ownership interest by an unrelated third party in the assets of Premier Integrated Technologies, Inc. (Premier), a company that we acquired on January 1, 2005. We have consolidated Premier in our accounts since the date of acquisition and record minority interest to reflect the ownership held by this third party. Prior to the Combination, IPS recorded the stock ownership of the minority shareholders in CES and IEM as minority interest. Upon consummation of the Combination, this minority interest was removed.

Discontinued Operations

Discontinued operations represent the results of operations, net of tax, of certain manufacturing and production enhancement operations of a Canadian subsidiary, including related assets located in south Texas. This disposal group was sold on October 31, 2006.

Liquidity and Capital Resources

Our primary liquidity needs are to fund capital expenditures, such as expanding our coiled tubing, wireline and production testing fleets, pressure pumping fleets and fluid handling equipment; increasing and replacing rental tool and well service rigs; and funding general working capital needs. In addition, we need capital to fund strategic business acquisitions. Our primary sources of funds have historically been cash flow from operations, proceeds from borrowings under bank credit facilities, a private placement of debt which was subsequently exchanged for publicly registered debt and the issuance of equity securities in our initial public offering.

On April 26, 2006, we sold 13,000,000 shares of our $.01 par value common stock in an initial public offering at an initial offering price to the public of $24.00 per share, which provided proceeds of approximately $292.5 million net of underwriters fees. We used these funds to retire principal and interest outstanding under our U.S. revolving credit facility on April 28, 2006 totaling approximately $127.5 million, to pay transaction costs of approximately $3.9 million and invested the remaining funds in tax-free and tax-advantaged municipal bonds and similar financial instruments. Of this amount, we utilized $141.6 million associated with acquisitions, including Arkoma, Turner and Pinnacle, and the remainder was used for other general corporate purposes. As of September 2006, all proceeds from our initial public offering had been utilized.

We anticipate that we will rely on cash generated from operations, borrowings under our amended revolving credit facility, future debt offerings and/or future public equity offerings to satisfy our liquidity needs. We believe that funds from these sources should be sufficient to meet both our short-term working capital requirements and our long-term capital requirements. We believe that our operating cash flows and availability under our amended revolving credit facility will be sufficient to fund our operations for the next twelve months. 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.

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

	Year Ended December 31,		
	2007	2006	2005
Cash flows provided by (used in):			
Operating activities	$ 338,560	$ 187,743	$ 76,427
Investing activities	(408,795)	(650,863)	(188,358)
Financing activities	66,643	471,376	112,139

Net cash provided by operating activities increased $150.8 million for the year ended December 31, 2007 compared to the year ended December 31, 2006. This increase was primarily due to an increase in gross receipts as a result of increased revenues. Our gross receipts increased throughout the three years ended December 31, 2007 as demand for our services grew, we invested in more equipment and logged incremental billable hours, while we continued to expand our current business and enter new markets through acquisitions. For the year ended December 31, 2006 compared to the year ended December 31, 2005, net cash provided by operating activities increased $111.3 million. This increase was also attributable to an increase in gross receipts, as revenues increased as a result of acquisitions, higher demand for our services and favorable pricing. We expect to continue to evaluate acquisition opportunities for the foreseeable future, and expect that new acquisitions will provide incremental operating cash flows.

Net cash used in investing activities declined by $242.1 million for the year ended December 31, 2007 compared to the year ended December 31, 2006, primarily due to a decline in the use of funds for acquisitions. During 2007, we focused our efforts on investing in organic growth through equipment purchases rather than investment in acquired businesses. During 2006, we invested more significantly in acquisitions to expand our geographic reach in areas where we have operations and into new basins within North America, while investing $303.9 million in capital equipment. Cash used in investing activities in 2006 was partially offset by $19.3 million received in cash related to the sale of certain discontinued operations. In addition, we invested $165.0 million in short-term investments, which were sold and used for the following purposes: (1) to acquire a series of businesses; (2) to make scheduled principal and interest payments on our credit facility; (3) to pay estimated federal income taxes; and (4) for other general corporate purposes. Significant capital equipment expenditures in 2007 included five coiled tubing units and over forty well service rigs, as well as additional pressure pumping units. Significant capital equipment expenditures in 2006 included coiled tubing units, pressure pumping equipment, well services rigs, fluid-handling equipment, rental equipment and drilling rigs. Significant capital equipment expenditures in 2005 included drilling rigs, well services rigs, fluid-handling equipment, rental equipment and coiled tubing equipment. See Significant Acquisitions above.

Net cash provided by financing activities decreased by $404.7 million for the year ended December 31, 2007 compared to the year ended December 31, 2006. The primary source of funds from financing activities in 2007 was net borrowings under our revolving credit facilities to fund capital expenditures, acquisitions, semi-annual interest payments on our senior notes and quarterly federal income tax payments. However, in 2006, the primary source of funds from financing activities was the receipt of the net proceeds from our initial public offering in April 2006, which provided approximately $288.6 million. In addition, we received net proceeds of $636.6 million from the issuance of 8.0% senior notes in December 2006, and we borrowed under our revolving credit facilities to fund various business acquisitions. The primary use of funds from financing activities was to repay $127.5 million outstanding under our U.S. revolving credit facility as of April 2006, with subsequent borrowings and repayments under this revolving credit facility throughout the year ended December 31, 2006, and the repayment of $419.0 million under our term loan facility in 2006, the majority of which was repaid in December 2006 from the proceeds of our senior note issuance. In 2005, we refinanced our term loan and revolving credit facilities, borrowed to finance the Parchman acquisition and borrowed additional funds for general corporate purposes. In addition, we received approximately $10.0 million from our private equity sponsor, in connection with the exercise of a stock warrant. Our long-term debt balances, including current maturities, were $826.7 million and $751.6 million as of December 31, 2007 and 2006, respectively.

We expect to expend approximately $150.0 million for investment in capital expenditures, excluding acquisitions, during the year ended December 31, 2008. We believe that our operating cash flows and borrowing capacity will be sufficient to fund our operations for the next 12 months.

In addition to investing in capital expenditures, we expect to continue to evaluate acquisitions of complementary companies. We evaluate each acquisition based upon the circumstances and our financing capabilities at that time.

Dividends

On September 12, 2005, we paid a dividend of $2.62 per share for an aggregate payment of approximately $146.9 million to stockholders of record on that date. 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

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, commencing on June 15, 2007. There was no discount or premium associated with the issuance of these notes. The senior notes are guaranteed, on a senior unsecured basis, 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) purchase or redeem stock or subordinated debt; (6) enter into transactions with affiliates; (7) merge with or into other companies or transfer all or substantially all 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. We can redeem 35% of these notes on or before December 15, 2009 using the proceeds of certain equity offerings. 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. On June 15, 2007 and December 15, 2007, we paid interest associated with these senior notes totaling $27.3 million and $26.0 million, respectively.

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 Securities and Exchange Commission which enabled these holders to exchange their notes for publicly registered notes with substantially identical terms. These holders exchanged 100% of these 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.

On December 6, 2006, we amended and restated our existing senior secured credit facility (the Credit Agreement) with Wells Fargo Bank, National Association, as U.S. Administrative Agent, and certain other financial institutions. The Credit Agreement initially provided for a $310.0 million U.S. revolving credit facility that will mature in 2011 and a $40.0 million Canadian revolving credit facility (with Integrated Production Services, Ltd., one of our wholly-owned subsidiaries, as the borrower thereof) that will mature in 2011. In addition, certain portions of the credit facilities are available to be borrowed in U.S. Dollars, Canadian Dollars, Pounds Sterling, Euros and other currencies approved by the lenders.

Subject to certain limitations, we have the ability to elect how interest under the Credit Agreement will be computed. Interest under the Credit Agreement may be determined by reference to (1) the London Inter-bank Offered Rate, or LIBOR, plus an applicable margin between 0.75% and 1.75% per annum (with the applicable margin depending upon our ratio of total debt to EBITDA (as defined in the agreement)), or (2) the Base Rate (i.e., the higher of the Canadian bank s prime rate or the CDOR rate plus 1.0%, in the case of Canadian loans or the greater of the prime rate and the federal funds rate plus 0.5%, in the case of U.S. loans), plus an applicable margin between 0.00% and 0.75% per annum. If an event of default exists under the Credit Agreement, advances will bear interest at the then-applicable rate plus 2%. Interest is payable quarterly for base rate loans and at the end of applicable interest periods for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest will be paid at the end of each three-month period.

The Credit Agreement also contains various covenants that limit our and our subsidiaries ability to: (1) grant certain liens; (2) make certain loans and investments; (3) make capital expenditures; (4) make distributions; (5) make acquisitions; (6) enter into hedging transactions; (7) merge or consolidate; or (8) engage in certain asset dispositions. Additionally, the Credit Agreement limits our and our subsidiaries ability to incur additional indebtedness if: (1) we are not in pro forma compliance with all terms under the Credit Agreement, (2) certain covenants of the additional indebtedness are more onerous than the covenants set forth in the Credit Agreement, or (3) the additional indebtedness provides for amortization, mandatory prepayment or repurchases of senior unsecured or subordinated debt during the duration of the Credit Agreement with certain exceptions. The Credit Agreement also limits additional secured debt to 10% of our consolidated net worth (i.e., the excess of our assets over the sum of our liabilities plus the minority interests). The Credit Agreement contains covenants which, among other things, require us and our subsidiaries, on a consolidated basis, to maintain specified ratios or conditions as follows (with such ratios tested at the end of each fiscal quarter): (1) total debt to EBITDA, as defined in the Credit Agreement, of not more than 3.0 to 1.0; and (2) EBITDA, as defined, to total interest expense of not less than 3.0 to 1.0. We were in compliance with all debt covenants under the amended and restated Credit Agreement as of December 31, 2007.

Under the Credit Agreement, we are permitted to prepay our borrowings.

All of the obligations under the U.S. portion of the Credit Agreement are secured by first priority liens on substantially all of 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 Credit Agreement are guaranteed by substantially all of our U.S. subsidiaries. All of the obligations under the Canadian portions of the Credit Agreement are secured by first priority liens on substantially all of the assets of our subsidiaries. Additionally, all of the obligations under the Canadian portions of the Credit Agreement are guaranteed by us as well as certain of our subsidiaries.

If an event of default exists under the Credit Agreement, as defined, the lenders may accelerate the maturity of the obligations outstanding under the Credit Agreement and exercise other rights and remedies. While an event of default is continuing, advances will bear interest at the then-applicable rate plus 2%. For a description of an event of default, see our Credit Agreement which was filed with the Securities and Exchange Commission on December 8, 2006 as an exhibit to a Current Report on Form 8-K.

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On June 29, 2007, we amended our Credit Agreement in conjunction with the restructuring of certain legal entities for tax purposes with no material changes to the financial provisions or covenants.

Effective October 19, 2007, we amended certain terms of our Credit Agreement including: (1) a provision to increase the borrowing capacity of the U.S. revolving portion of the facility from $310.0 million to $360.0 million; and (2) a provision to include a commitment increase clause, as defined in our Credit Agreement, which permits us to effect up to two separate increases in the aggregate commitments under the facility by designating a participating lender to increase its commitment, by mutual agreement, in increments of at least $50.0 million with the aggregate of such commitment increases not to exceed $100.0 million and in accordance with other provisions as stipulated in the amendment. In addition, the amendment specifies the terms for prepayment of outstanding advances and new borrowings and replaces Schedule II to the amended Credit Agreement which allocates the commitments amongst the member financial institutions.

Borrowings of $160.0 million and $12.2 million were outstanding under the U.S. and Canadian revolving credit facilities at December 31, 2007, respectively. The U.S. revolving credit facility bore interest at rates ranging from 6.45% to 7.50% at December 31, 2007, and the Canadian revolving credit facility bore interest at 6.25% at December 31, 2007. For the year ended December 31, 2007, the weighted average interest rate on borrowings under the amended Credit Agreement was approximately 6.56%. In addition, there were letters of credit outstanding which totaled $37.9 million under the U.S. revolving portion of the facility that reduced the available borrowing capacity at December 31, 2007 to $162.1 million under the U.S. revolving portion of the facility and $27.8 million under the Canadian revolving portion of the facility. In addition, we incurred fees of 1.25% of the total amount outstanding under our letter of credit arrangements. As of February 1, 2008, we had $182.7 million outstanding under our Credit Agreement.

In accordance with the subordinated notes issued in conjunction with the acquisition of Parchman in February 2005, all principal and interest under these note arrangements totaling $5.0 million was repaid as of May 2, 2006.

Other Arrangements

We received $7.4 million from customers in 2005 as advance payments on the construction and operation of two drilling rigs for our contract drilling operations in north Texas. The drilling rigs were completed and placed into service in October 2005 and January 2006. Revenue was recognized over the agreed service contract. All revenue under these contracts was recognized prior to December 31, 2006.

Outstanding Debt and Operating Lease Commitments

The following table summarizes our known contractual obligations as of December 31, 2007 (in thousands):

		Payments Due by Period			
Contractual Obligations	**Total**	**2008**	**2009-2010**	**2011-2012**	**Thereafter**
Long-term debt, including capital (finance) lease obligations	$ 822,443	$ 147	$ 77	$ 172,219	$ 650,000
Interest on 8% senior notes issued December 6, 2006	463,667	52,000	104,000	104,000	203,667
Purchase obligations(1)	21,004	21,004			
Operating lease obligations	53,940	20,222	21,211	8,125	4,382
Other long-term obligations(2)	4,219	528	3,666	25	

Total contractual obligations	$ 1,365,273	$ 93,901	$ 128,954	$ 284,369	$ 858,049

(1) Purchase obligations were pursuant to non-cancelable equipment purchase orders outstanding as of December 31, 2007. We have no significant purchase orders which extend beyond one year.

(2) Other long-term obligations include amounts due under subordinated note arrangements with maturity dates beginning in 2009 and loans relating to equipment purchases which mature at various dates through September 2010.

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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 have spent $372.6 million for equipment purchases and other capital expenditures during the year ended December 31, 2007, which does not include amounts paid in connection with acquisitions.

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

In June 2006, the FASB issued an interpretation entitled Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, referred to as FIN 48. FIN 48 clarifies the accounting for uncertain tax positions that may have been taken by an entity. Specifically, FIN 48 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 FIN 48, 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 be derecognized in the first financial reporting period that the threshold is no longer met. We adopted FIN 48 on January 1, 2007 with no material impact on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115. This pronouncement permits entities to use the fair value method to measure certain financial assets and liabilities by electing an irrevocable option to use the fair value method at specified election dates. After election of the option, subsequent changes in fair value would result in the recognition of unrealized gains or losses as period costs during the period the change occurred. SFAS No. 159 becomes effective as of the beginning of the first fiscal year that begins after November 15, 2007, with early adoption permitted. However, entities may not retroactively apply the provisions of SFAS No. 159 to fiscal years preceding the date of adoption.

In February 2008, the FASB issued FASB Staff Position No. 157-2 which postpones certain provisions of SFAS No. 157 related to disclosure requirements for non-financial assets and liabilities except for items which are recognized and disclosed at fair value in the financial statements on a recurring basis. We adopted SFAS No. 157 on January 1, 2007. For additional disclosure related to SFAS No. 157, see Note 2, Significant Accounting Policies in the accompanying Notes to the Consolidated Financial Statements at December 31, 2007.

In May 2007, the FASB issued FASB Staff Position FIN 48-1, an amendment to FIN 48, which provides 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

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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 will apply this guidance going forward, as applicable.

In December 2007, the FASB issued SFAS No. 160, Non-controlling Interests in Consolidating Financial Statements an Amendment of ARB No. 51. This pronouncement establishes accounting and reporting standards for non-controlling interests, commonly referred to as minority interests. Specifically, this statement requires that the non-controlling interest be presented as a component of equity on the balance sheet, and that net income be presented prior to adjustment for the non-controlling interests portion of earnings with the portion of net income attributable to the parent company and the non-controlling interest both presented on the face of the statement of operations. In addition, this pronouncement provides a single method of accounting for changes in the parent s ownership interest in the non-controlling entity, and requires the parent to recognize a gain or loss in net income when a subsidiary with a non-controlling interest is deconsolidated. Additional disclosure items are required related to the non-controlling interest. This pronouncement becomes effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The statement should be applied prospectively as of the beginning of the fiscal year that the statement is adopted. However, the disclosure requirements must be applied retrospectively for all periods presented. We are currently evaluating the impact that SFAS No. 160 may have on our financial position, results of operations and cash flows.

In December 2007, the FASB revised SFAS No. 141, Business Combinations which will replace that pronouncement in its entirety. While the revised statement will retain the fundamental requirements of SFAS No. 141, it will also require 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, the statement provides guidance for recognizing pre-acquisition contingencies and states that an acquirer must recognize assets and liabilities assumed arising from contractual contingencies as of the acquisition date, measured at acquisition-date fair values, but 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 FASB Concepts Statement No. 6, Elements of Financial Statements. Furthermore, this statement 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 it requires that the acquirer recognize that excess in earnings as a gain attributable to the acquirer. This statement becomes effective at the beginning of the first annual reporting period beginning on or after December 15, 2008, and must be applied prospectively. We are currently evaluating the impact that this statement 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

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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, 2007 and 2006, approximately 5% and 7% of our revenues from continuing operations, respectively, and 6% and 8% of our total assets, respectively, 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, 2007 by approximately $0.8 million. 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, 2007 by approximately $0.4 million. Currently, we conduct a portion of our business in Mexico in the local currency, the Mexican peso.

Approximately 21% of our debt at December 31, 2007 is structured under floating rate terms and, as such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. and Canada. Based on the debt structure in place as of December 31, 2007, a 100 basis point increase in interest rates relative to our floating rate obligations would increase interest expense by approximately $1.7 million per year and reduce operating cash flows by approximately $1.1 million, net of tax.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Complete Production Services, Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, comprehensive income, stockholders equity and cash flows for each of the three years in the period ended December 31, 2007. 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 audits 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 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Complete Production Services, Inc. and subsidiaries as of December 31, 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payments. In addition, as discussed in Note 2 to the consolidated financial statements, effective January 1, 2007, the Company adopted the provisions of Financial Accounting Standards No. 157, Fair Value Measurements .

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Complete Production Services, Inc. and subsidiaries internal control over financial reporting as of December 31, 2007, 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 29, 2008, expressed an unqualified opinion that Complete Production Services, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting.

/s/ Grant Thornton LLP

Houston, Texas
February 29, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Complete Production Services, Inc. s internal control over financial reporting as of December 31, 2007, 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 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, 2007, based on criteria established in *Internal Control Integrated Framework issued by COSO*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Complete Production Services, Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations and comprehensive income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007, and our report dated February 29, 2008 expressed an unqualified opinion on those consolidated financial statements.

/s/ Grant Thornton LLP

Houston, Texas
February 29, 2008

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COMPLETE PRODUCTION SERVICES, INC.

Consolidated Balance Sheets
December 31, 2007 and 2006

	2007	2006
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,681	$ 19,874
Trade accounts receivable, net of allowance for doubtful accounts of $5,737 and $2,431, respectively	328,685	301,764
Inventory, net of obsolescence reserve of $2,420 and $1,719, respectively	57,068	43,930
Prepaid expenses	23,798	24,998
Other current assets	5,092	74
Total current assets	428,324	390,640
Property, plant and equipment, net	1,034,695	771,703
Intangible assets, net of accumulated amortization of $6,742 and $3,623, respectively	10,794	7,765
Deferred financing costs, net of accumulated amortization of $2,455 and $547, respectively	14,194	15,729
Goodwill	560,488	552,671
Other long-term assets	6,264	1,816
Total assets	$ 2,054,759	$ 1,740,324
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 675	$ 1,064
Accounts payable	64,667	71,370
Accrued liabilities	57,841	39,063
Accrued payroll and payroll burdens	24,502	22,302
Notes payable	15,354	17,087
Taxes payable	6,506	10,519
Total current liabilities	169,545	161,405
Long-term debt	825,987	750,577
Deferred income taxes	128,904	90,805
Minority interest		2,316
Total liabilities	1,124,436	1,005,103
Commitments and contingencies		
Stockholders equity:		

Common stock, $0.01 par value per share, 200,000,000 shares authorized, 72,509,511 (2006 71,418,473) issued	725	714
Preferred stock, $0.01 par value per share, 5,000,000 shares authorized, no shares issued and outstanding		
Additional paid-in capital	581,404	563,006
Retained earnings	317,535	155,971
Treasury stock, 35,570 shares at cost	(202)	(202)
Accumulated other comprehensive income	30,861	15,732
Total stockholders equity	930,323	735,221
Total liabilities and stockholders equity	$ 2,054,759	$ 1,740,324

See accompanying notes to consolidated financial statements.

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COMPLETE PRODUCTION SERVICES, INC.

Consolidated Statements of Operations
Years Ended December 31, 2007, 2006 and 2005

	Year Ended December 31,		
	2007	**2006**	**2005**
	(In thousands, except per share data)		
Revenue:			
Service	$ 1,502,477	$ 1,088,748	$ 639,421
Product	152,760	123,676	80,768
	1,655,237	1,212,424	720,189
Service expenses	863,705	622,786	393,856
Product expenses	116,557	88,175	56,862
Selling, general and administrative expenses	210,147	167,334	108,766
Depreciation and amortization	135,961	79,465	48,510
Income from continuing operations before interest, taxes and minority interest	328,867	254,664	112,195
Interest expense	62,673	40,759	24,460
Interest income	(1,636)	(1,387)	
Write-off of deferred financing costs		170	3,315
Impairment loss	13,094		
Income from continuing operations before taxes and minority interest	254,736	215,122	84,420
Taxes	93,741	77,888	33,115
Income from continuing operations before minority interest	160,995	137,234	51,305
Minority interest	(569)	(49)	384
Income from continuing operations	161,564	137,283	50,921
Income from discontinued operations (net of tax expense of $0, $1,987 and $601, respectively)		1,803	2,941
Net income	$ 161,564	$ 139,086	$ 53,862
Earnings per share information:			
Continuing operations	$ 2.24	$ 2.09	$ 1.09
Discontinued operations	$	$ 0.02	$ 0.07
Basic earnings per share	$ 2.24	$ 2.11	$ 1.16
Continuing operations	$ 2.20	$ 2.02	$ 1.00
Discontinued operations	$	$ 0.02	$ 0.06

Diluted earnings per share	$ 2.20	$ 2.04	$ 1.06
Weighted average shares:			
Basic	71,991	65,843	46,603
Diluted	73,352	68,075	50,656

See accompanying notes to consolidated financial statements.

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COMPLETE PRODUCTION SERVICES, INC.

Consolidated Statements of Comprehensive Income
Years Ended December 31, 2007, 2006 and 2005

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Net income	$ 161,564	$ 139,086	$ 53,862
Change in cumulative translation adjustment	15,129	(808)	2,043
Comprehensive income	$ 176,693	$ 138,278	$ 55,905

See accompanying notes to consolidated financial statements.

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COMPLETE PRODUCTION SERVICES, INC.

Consolidated Statement of Stockholders Equity
Years Ended December 31, 2007, 2006 and 2005

	Number of Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Deferred Compensation	Accumulated Other Comprehensive Income	Total
	(In thousands, except share data)							
Balance at December 31, 2004	38,895,220	$ 389	$ 143,147	$ 14,799	$	$ (752)	$ 14,497	$ 172,080
Net income				53,862				53,862
Cumulative translation adjustment							2,043	2,043
Issuance of common stock:								
Acquisition of Parchman	2,655,336	27	16,861					16,888
Acquisition of Spindletop	90,364		1,053					1,053
Exercise of warrants	2,048,526	20	9,980					10,000
For cash	136,376	1	1,403					1,404
Exercise of stock options	15,082		79					79
Purchase of warrants			(256)					(256)
Stock compensation	16,096		187					187
Expense related to employee stock options			230					230
Issuance of restricted stock	153,736	2	4,616			(4,618)		
Amortization of deferred compensation						1,747		1,747
Purchase of minority interest	11,556,344	116	138,604			(180)		138,540
Dividend paid			(95,118)	(51,776)				(146,894)
Repurchase of common stock	(35,570)				(202)			(202)
Balance at December 31, 2005	55,531,510	$ 555	$ 220,786	$ 16,885	$ (202)	$ (3,803)	$ 16,540	$ 250,761
Adoption of SFAS No. 123R			(3,803)			3,803		
Net income				139,086				139,086

Cumulative translation adjustment							(808)	(808)
Issuance of common stock:								
Net proceeds from initial public offering	13,000,000	130	288,505					288,635
Acquisition of Parchman	1,000,000	10	23,490					23,500
Acquisition of MGM	164,210	2	3,857					3,859
Acquisition of Pumpco	1,010,566	10	21,414					21,424
Exercise of stock options	506,405	5	1,810					1,815
Expense related to employee stock options			1,848					1,848
Excess tax benefit from share-based compensation			2,333					2,333
Vested restricted stock	205,782	2	(2)					
Amortization of non-vested restricted stock			2,768					2,768
Balance at December 31, 2006	71,418,473	$ 714	$ 563,006	$ 155,971	$ (202)	$	$ 15,732	$ 735,221
Net income				161,564				161,564
Cumulative translation adjustment							15,129	15,129
Issuance of common stock:								
Exercise of stock options	934,094	9	4,170					4,179
Expense related to employee stock options			4,426					4,426
Excess tax benefit from share-based compensation			6,662					6,662
Vested restricted stock	156,944	2	(2)					
Amortization of non-vested restricted stock			3,142					3,142
Balance at December 31, 2007	72,509,511	$ 725	$ 581,404	$ 317,535	$ (202)	$	$ 30,861	$ 930,323

See accompanying notes to consolidated financial statements.

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COMPLETE PRODUCTION SERVICES, INC.

Consolidated Statements of Cash Flows
Years Ended December 31, 2007, 2006 and 2005

	Year Ended December 31, 2007	2006 (In thousands)	2005
Cash provided by:			
Net income	$ 161,564	$ 139,086	$ 53,862
Items not affecting cash:			
Depreciation and amortization	135,961	79,813	48,840
Deferred income taxes	38,099	30,907	17,993
Impairment loss	13,094		
Write-off of deferred financing fees		170	3,315
Loss on sale of discontinued operations		603	
Minority interest	(569)	(49)	384
Excess tax benefit from share-based compensation	(6,662)	(2,333)	
Non-cash compensation expense	7,568	4,616	1,984
Provision for/(recoveries of) bad debt expense	7,277	2,329	1,332
Other	3,391	1,564	1,119
Changes in operating assets and liabilities, net of effect of acquisitions:			
Accounts receivable	(29,255)	(105,203)	(69,755)
Inventory	(11,132)	(11,511)	(18,346)
Prepaid expenses and other current assets	1,520	(1,201)	(4,903)
Accounts payable	(8,063)	14,819	18,647
Accrued liabilities and other	25,767	34,133	21,955
Net cash provided by operating activities	338,560	187,743	76,427
Investing activities:			
Business acquisitions, net of cash acquired	(50,406)	(369,606)	(67,689)
Additions to property, plant and equipment	(367,659)	(303,922)	(125,142)
Purchase of short-term securities		(165,000)	
Proceeds from sale of short-term securities		165,000	
Proceeds from sale of fixed assets	9,270	3,355	4,473
Proceeds from sale of disposal group		19,310	
Net cash used in investing activities	(408,795)	(650,863)	(188,358)
Financing activities:			
Issuances of long-term debt	343,790	608,703	741,599
Repayments of long-term debt	(268,769)	(1,053,789)	(464,605)
Net repayments under lines of credit			(19,603)
Repayment of convertible debentures			(4,069)
Repayments of notes payable	(18,846)	(13,589)	(1,690)
Borrowings under senior notes		650,000	
Proceeds from issuances of common stock	4,179	291,674	12,267
Dividend paid			(146,894)

Repurchase of common stock/warrants			(458)
Deferred financing fees	(373)	(13,956)	(4,408)
Excess tax benefit from share-based compensation	6,662	2,333	
Net cash provided by financing activities	66,643	471,376	112,139
Effect of exchange rate changes on cash	(2,601)	213	(350)
Change in cash and cash equivalents	(6,193)	8,469	(142)
Cash and cash equivalents, beginning of period	19,874	11,405	11,547
Cash and cash equivalents, end of period	$ 13,681	$ 19,874	$ 11,405
Supplemental cash flow information:			
Cash paid for interest, net of interest capitalized	$ 59,164	$ 35,947	$ 23,718
Cash paid for taxes	$ 56,468	$ 40,132	$ 15,138
Significant non-cash investing and financing activities:			
Common stock issued for acquisitions	$	$ 48,783	$ 20,118
Non-cash consideration for acquisitions	$	$	$ 13,699
Debt acquired in acquisition	$	$ 30,784	$
Acquisition of minority interest	$	$	$ 93,792
Notes issued for equipment	$	$	$ 1,281
Capital expenditures in accrued payables/expenses	$ 4,895	$	$ 792

See accompanying notes to consolidated financial statements.

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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, Kansas, western Canada, Mexico and Southeast Asia.

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

On September 12, 2005, we completed the combination (the Combination) of Complete Energy Services, Inc. (CES), Integrated Production Services, Inc. (IPS) and I.E. Miller Services, Inc. (IEM). CES, incorporated on November 7, 2003, provides integrated wellsite services including a wide range of services to the oil and gas exploration industry, and operates in north and east Texas as well as in the Mid-Continent and the Rocky Mountain regions of the United States. IPS is a Delaware corporation, formerly named Saber Energy Services, Inc. (Saber), which was incorporated on May 22, 2001. Saber combined with Integrated Production Services Ltd. (IPSL) on September 20, 2002, accounted for as a continuity of interests transaction since both entities were controlled by a common shareholder, and the combined entity changed its name to Integrated Production Services, Inc. IPS provides a wide range of services and products to the oil and gas industry designed to reduce customers operating costs and increase production from customers hydrocarbon reserves. IPS has operations in western Canada, Texas, Louisiana, Mexico and Southeast Asia. IEM was incorporated on August 26, 2004 to acquire certain businesses that perform land rig moving services in Louisiana and Texas and vacuum truck services in south Louisiana.

Pursuant to the Combination, CES and IEM shareholders exchanged all of their common stock for common stock of IPS. The Combination was accounted for using the continuity of interests method of accounting, which yields results similar to the pooling of interest method. CES shareholders received 19.704 shares of IPS for each share of CES, and IEM shareholders received 19.410 shares of IPS for each share of IEM. Subsequent to the Combination, IPS changed its name to Complete Production Services, Inc. As of September 12, 2005, the former CES shareholders owned 57.6% of our common shares, IPS shareholders owned 33.2% and the former IEM shareholders owned 9.2%. IPS was treated as the acquirer of the minority interest ownership in CES and IEM as a result of the Combination. The minority interest ownership in net income of CES and IEM for the years prior to the date of the Combination is calculated based upon the percentage of equity ownership not held by the common controlling shareholder. The consolidated financial statements have been adjusted to reflect minority interest ownership in Complete for all periods presented prior to the date of the Combination.

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 14, 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 (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

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

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, 2007 and 2006 and the statements of operations, the statements of comprehensive income, the statements of stockholders equity and the statements of cash flows for each of the three years in the period ended December 31, 2007. We believe that these financial statements contain all adjustments necessary so that they are not misleading. Certain reclassifications have been made to 2005 and 2006 amounts in order to present these results on a comparable basis with amounts for 2007.

In August 2006, our Board of Directors authorized and committed to a plan to sell certain manufacturing and production enhancement operations of a subsidiary located in Alberta, Canada, which includes certain assets located in south Texas. Accordingly, we have revised our financial statements for all periods presented to classify the related results of operations of this disposal group as discontinued operations. See Note 16, 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 year. 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 has been 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, 2007 and 2006.

(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,

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

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 common stock equivalents.

(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 and materials and supplies held for resale, is carried at the lower of cost and 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
Gas 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-

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

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 5 years as of December 31, 2007.

(i) Impairment of long-lived assets:

In accordance with Statement of Financial Accounting Standards (SFAS) No. 144, long-lived assets, such as property, plant and equipment, and purchased intangibles subject to amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of 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.

(j) Asset retirement obligations:

We account for asset retirement obligations in accordance with SFAS No. 143, Accounting for Asset Retirement Obligations , pursuant to which we would record the fair value of an asset retirement obligation 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. Furthermore, we would record a corresponding asset to depreciate over the contractual term of the underlying asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation would be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. There were no significant retirement obligations recorded at December 31, 2007 and 2006.

(k) Deferred financing costs:

Deferred financing costs associated with long-term debt under 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. We apply the provisions of SFAS No. 142, which 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 analysis consistent with that described in SFAS No. 141. 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, as described in SFAS No. 142. We recorded an impairment loss for the year ended December 31, 2007. See Note 17, Segment Information and Note 2, Significant Accounting Policies Fair Value Measurement. Based upon this testing, goodwill was not deemed to be impaired during the years ended December 31, 2006 and 2005.

(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 reserve when we believe that it is more likely than not that any deferred tax asset created will not be realized.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

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, bank operating loans, accounts payable and accrued liabilities, long-term debt, convertible debentures and senior notes. The fair value of all financial instruments approximates 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, 2007, the fair value of these notes was $627,250, based on the published closing price. At December 31, 2006, the fair value of these notes was deemed to approximate the face value of the notes due to the relatively short period between the date of issuance and December 31, 2006.

(o) Per share amounts:

We use the treasury stock method described in SFAS No. 128 to calculate the dilutive effect of stock options, stock warrants, convertible debentures and non-vested restricted stock. 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 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 grants of stock options prior to January 1, 2006, stock options were accounted for under Accounting Principles Board (APB) No. 25, Accounting for Stock Issued to Employees, whereby no compensation expense was recorded if 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 which would have been required under SFAS No. 123. We adopted SFAS No. 123R on January 1, 2006. Pursuant to SFAS No. 123R, 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 of SFAS No. 123R to account for these grants and record compensation expense. See Note 14, 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 SFAS No. 143 arising 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.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

(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, property plant and equipment useful lives, 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:

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, a pronouncement which provides guidance for using fair value to measure assets and liabilities by providing a definition of fair value, stating that fair value should be based upon assumptions market participants would use to price an asset or liability, and establishing a hierarchy that prioritizes the information used to determine fair value, whereby quoted market prices in active markets would be given highest priority with lowest priority given to data provided by the reporting entity based on unobservable facts. SFAS No. 157 requires disclosure of significant fair value measurements by level within the prescribed hierarchy. We adopted SFAS No. 157 on January 1, 2007, and have applied its guidance prospectively.

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 accounted for pursuant to SFAS No. 141; (2) valuing potential impairment loss related to goodwill and indefinite-lived intangible assets accounted for pursuant to SFAS No. 142; and (3) valuing potential impairment loss related to long-lived assets accounted for pursuant to SFAS No. 144. We generally do not hold trading securities, and we were not party to significant derivative contract arrangements during the year ended December 31, 2007. We evaluated our long-lived assets in accordance with SFAS No. 144 and determined that our long-lived assets were not impaired as of December 31, 2007. We evaluated our acquisition transactions completed during 2007 in accordance with SFAS No. 141 and determined that these acquired businesses were not significant to our overall financial statement presentation at December 31, 2007, and thus were not subject to the disclosure requirements of SFAS No. 157. We evaluated our goodwill and indefinite-lived intangible assets in accordance with the recoverability tests prescribed by SFAS No. 142 and determined that the goodwill associated with one of our reportable units, our Canadian completion and production services business, was deemed to be impaired as of the testing date.

In performing the two-step goodwill impairment test prescribed by SFAS No. 142, 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 analysis, we determined that goodwill associated with our Canadian operation was impaired as of the test date, 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 this reportable unit. The inputs for this model were largely unobservable estimates from management based on historical performance. Due to modifications and the highly customized nature of the property, plant and equipment of this reportable unit, collecting specific market price data to assess the fair value of these assets was not feasible, although general market data was obtained. 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

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

of $13,360 for this reportable unit, of which $13,094 was recorded as an impairment loss in the accompanying statement of operations at December 31, 2007. This impairment charge was allocated entirely to the completion and production services business segment and was deemed necessary due to an overall decline in oil and gas exploration and production activity in Canada. Of the goodwill maintained on the books of our Canadian subsidiary, the majority was derived from acquisition transactions which occurred prior to the Combination in September 2005. We intend to continue to hold our investment in our Canadian operation for the foreseeable future.

The following tabular presentation is presented in accordance with SFAS No. 157 for quantitative presentation of our significant fair value measurements at December 31, 2007:

Description	Carrying Value Prior to Impairment Charge	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Gains (Losses)
Goodwill	573,848			$ 560,488	$ (13,360)
	573,848			$ 560,488	$ (13,360)

In accordance with SFAS No. 142, goodwill with a carrying amount of $573,848 was written down to its implied fair value of $560,488, resulting in an impairment charge of $13,360, of which $13,094 was recorded as an impairment loss and $266 was recorded as a charge to cumulative translation adjustment in the accompanying balance sheet as of December 31, 2007.

3. Business combinations:

(a) Acquisitions During the Year Ended December 31, 2007:

During the year ended December 31, 2007, we acquired substantially all the assets or all of the equity interests in six oilfield service businesses, and the remaining 50% interest in our Canadian joint venture, for $49,691 in cash, resulting in goodwill of $19,391. Several of these acquisitions are subject to final working capital adjustments. These acquisitions in 2007 were as follows:

(i) On January 4, 2007, we acquired substantially all of the assets of a company located in LaSalle, Colorado, which provides frac tank rental and fresh water hauling services to customers in the Wattenburg Field of the DJ Basin, which supplements our fluid handling and rental business in the Rocky Mountain region.

(ii) On February 28, 2007, we acquired substantially all of the assets of a company located in Greeley, Colorado, which provides fluid handling and fresh frac water heating services to customers in the Wattenburg Field of the DJ

Basin, which also supplements our fluid handling business in the Rocky Mountain region.

(iii) On April 1, 2007, we acquired substantially all of the assets of a company located in Borger, Texas, which provides fluid handling and disposal services to customers in the Texas panhandle. We believe this acquisition complements certain operations that we acquired in 2006 within the Texas panhandle area and broadens our ability to provide fluid handling and disposal services throughout the Mid-continent region.

(iv) On June 8, 2007, we acquired all the membership interests in a business located in Rangely, Colorado, which provides rig workover and roustabout services to customers in the Rangely Weber Sand Unit and northern Piceance Basin area. This acquisition expands our geographic reach in the northern Piceance Basin, expands our workover rig capabilities and provides a beneficial customer relationship.

(v) On October 18, 2007, we acquired all of the outstanding common stock of a company located in Kilgore, Texas, which provides remedial cement and acid services used in pressure pumping operations to customers throughout the east Texas region. This acquisition supplements our pressure pumping business and expands our presence in east Texas.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

(vi) On November 30, 2007, we acquired substantially all of the assets of a company located in Greeley, Colorado, which is an e-line service provider to customers in the Wattenberg Field of the DJ Basin. This acquisition supplements our completion and production services business in the Rocky Mountain region.

(vii) On December 31, 2007, we acquired the remaining 50% interest in our joint venture in Canada for approximately $1,600. This transaction resulted in a decrease in goodwill of $595, as the amount paid was less than the minority interest liability related to this operation just prior to the acquisition. This company provides optimization services in the Canadian market.

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 intangibles 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. We do not deem these acquisitions to be significant to our consolidated operations for the year ended December 31, 2007. The following table summarizes our preliminary purchase price allocations for these acquisitions as of December 31, 2007, several of which are yet to be finalized:

Net assets acquired:	
Property, plant and equipment	$ 25,081
Non-cash working capital	1,397
Minority interest liability	2,188
Intangible assets	2,144
Long-term deferred tax liabilities	(510)
Goodwill	19,391
Net assets acquired	$ 49,691
Consideration:	
Cash, net of cash and cash equivalents acquired	$ 49,691

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. To determine the fair value of assets acquired, we generally retain 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 are deemed to be acquired at fair market value.

(b) Acquisitions During the Year Ended December 31, 2006:

(i) Outpost Office Inc. (Outpost):

On January 3, 2006, we acquired all of the operating assets of Outpost Office Inc., an oilfield equipment rental company based in Grand Junction, Colorado, for $6,542 in cash, and recorded goodwill of $2,348, which has been allocated entirely to the completion and production services business segment. We believe this acquisition supplemented our completion and production services business in the Rocky Mountain Region.

(ii) The Rosel Company (Rosel):

On January 25, 2006, we acquired all the equity interests of The Rosel Company, a cased-hole and open-hole electric-line business based in Liberal, Kansas, for $11,953, in cash, net of cash acquired and debt assumed, and recorded goodwill of $7,997 resulting from this acquisition, which has been allocated entirely to the completion and

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

production services business segment. We believe this acquisition expanded our presence in the Mid-continent region and enhanced our completion and production services business.

(iii) The Arkoma Group of Companies (Arkoma):

On June 30, 2006, we acquired certain operating assets of J&M Rental Tool, Inc. dba Arkoma Machine & Fishing Tools, Arkoma Machine Shop, Inc. and N&M Supply, LLC, collectively referred to as The Arkoma Group of Companies, a provider of rental tools, machining and fishing services in the Fayetteville Shale and Arkoma Basin, located in Ft. Smith, Arkansas. We paid $18,002 in cash to acquire Arkoma, subject to a final working capital adjustment, and recorded goodwill totaling $8,993, which has been allocated entirely to the completion and production services business segment. We believe this acquisition provides a platform to further expand our presence in the Fayetteville Shale and Arkoma Basin and supplement our completion and production services business in that region.

(iv) CHB Holdings Partnership, Ltd. (CHB):

On July 17, 2006, we acquired all the assets of CHB Holdings Partnership, Ltd., a fluid handling and disposal services business located in Henderson, Texas, for $12,738 in cash, and recorded goodwill of $8,087, which was allocated entirely to the completion and production services business segment. We believe this acquisition is complementary to our fluid handling business in the Bossier Trend region of east Texas.

(v) Turner Group of Companies (Turner):

On July 28, 2006, we acquired all of the outstanding equity interests of the Turner Group of Companies (Turner Energy Services, LLC, Turner Energy SWD, LLC, T. & J. Energy, LLC, T. & J. SWD, LLC and Lloyd Jones Well Service, LLC) for $54,328 in cash, after a final working capital adjustment, and recorded goodwill totaling $16,046. The Turner Group of Companies (Turner) is based in the Texas panhandle in Canadian, Texas, and owns a fleet of well service rigs, and provides other wellsite services such as fishing, equipment rental, fluid handling and salt water disposal services. We included the accounts of Turner in our completion and production services business segment and believe that Turner supplements our completion and production business in the Mid-continent region.

(vi) Quinn Well Control Ltd. (Quinn):

On July 31, 2006, we acquired certain assets of Quinn Well Control Ltd., a slick line business located in Grande Prairie, Alberta, Canada, for $8,876 in cash and recorded goodwill of $4,247. We included the accounts of Quinn in our completion and production services business segment. We believe this acquisition enhances our Canadian slick-line business and expands our geographic reach in northern Alberta and northeast British Columbia.

(vii) Pinnacle Drilling Co., L.L.C. (Pinnacle):

On August 1, 2006, we acquired substantially all of the assets of Pinnacle Drilling Co., L.L.C., a drilling company located in Tolar, Texas, for $31,703 in cash and recorded goodwill totaling $1,049. In addition, we paid $1,073 in cash related to this equipment during the fourth quarter of 2006. In 2007, we received $579 from the seller related to certain pre-acquisition contingencies, resulting in a decrease in goodwill. Pinnacle operates three drilling rigs, two in the Barnett Shale region in north Texas and one in east Texas. We included the accounts of Pinnacle in our drilling services business segment. We believe this acquisition increased our presence in the Barnett Shale of north Texas and the Bossier Trend of east Texas and expands our capacity to drill deep and horizontal wells, which are sought by our customers in this region.

(viii) Oilfield Airfoam and Rentals I, LP (Airfoam):

On August 15, 2006, we acquired substantially all of the assets of Oilfield Airfoam and Rentals I, LP, a fishing and rental services business located in Pocola, Oklahoma, with operations in eastern Oklahoma and western

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Arkansas, for $6,939 in cash and recorded goodwill totaling $3,115. We paid an additional $1,180 in cash for capital equipment in process at the time of the acquisition but not received until October 2006. We included Airfoam in our completion and production services business segment. We believe this acquisition complements our completion services business in the Fayetteville Shale.

(ix) Scientific Microsystems Inc. (SMI):

On August 31, 2006, we acquired all the outstanding common stock of Scientific Microsystems, Inc., for $2,900 in cash at closing, with a potential to pay an additional $200 subject to a final working capital adjustment, and recorded goodwill totaling $1,774. SMI is located in Waller, Texas, and is a manufacturer of a conventional line of plunger lift systems and related controllers, and a provider of related engineering services. In 2007, we paid $800 pursuant to an earn-out agreement with the former owners of SMI, based upon certain defined operating targets for the period from the date of acquisition through September 30, 2007. We included SMI in our completion and production services business segment. We believe the artificial lift systems manufactured by SMI complements our proprietary Pacemaker Plunger[tm] product.

(x) Drilling Fluid Services, LLC (DFS) and KCL Company, LLC (KCL):

On September 15, 2006, we acquired substantially all of the assets of Drilling Fluid Services, LLC and KCL Company, LLC, each of which is located in Greeley, Colorado, and provide chemicals used for completion services to customers in the Wattenberg Field of the Denver-Julesburg Basin in Colorado. We paid a total of $4,250 in cash, or $2,125 each, to acquire DFS and KCL, and recorded goodwill of $1,872 and $1,847, respectively. We have included the operations of DFS and KCL in our completion and production services business segment. We believe these companies complement our completion and production services business in the Rocky Mountain region.

(xi) Anderson Water Well Service, Ltd. (Anderson):

On September 29, 2006, we acquired substantially all of the assets of Anderson Water Well Service, Ltd., located in Bridgeport, Texas, for $10,760 in cash and we recorded goodwill totaling $7,914. In addition, we issued 38,268 shares of our non-vested restricted stock to the former owners of Anderson, valued at the closing price of our common stock on September 29, 2006, or an aggregate of $755, which will be expensed ratably through September 29, 2008. Anderson drills wells to source water used for hydraulic fractures in the Barnett Shale. We have included the operations of Anderson in our completion and production services business segment. We believe the acquisition of Anderson strengthens our current water well-drilling business in the Barnett Shale area.

(xii) Jim Lee Trucking, Inc. (Jim Lee):

On October 13, 2006, we acquired substantially all the assets of Jim Lee Trucking, Inc. (Jim Lee), a company located in Rock Springs, Wyoming, for $5,000 in cash and we recorded goodwill totaling $3,842. Jim Lee is engaged in the business of hauling barite and other additives for customers in the Greater Green River Basin. We included the accounts of Jim Lee in our completion and production services business segment from the date of acquisition. We believe this acquisition is complementary to our completion and production services business in the Rocky Mountain region.

(xiii) Brothers Group of Companies (Brothers):

On October 13, 2006, we acquired substantially all the assets of Brothers Industries, Ltd., Brothers Well Service, Ltd., Brothers Trucking Service, Ltd., Brothers Supply Company, Ltd., and BWS Vacuum Service, Ltd., collectively the Brothers Industries Group of Companies (Brothers) for $6,936 in cash, with an additional potential payment of up to $545 related to a final adjustment, and we recorded goodwill totaling $2,859. Brothers is located in El Campo, Texas, and provides various completion and production services, and has supply store operations. We included the accounts of Brothers in our completion and production services business segment from

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

the date of acquisition. We believe this acquisition supplements our completion and production services business in the Texas region and expands our availability of products throughout the geographic regions we serve.

(xiv) Femco Group of Companies (Femco):

On October 19, 2006, we acquired substantially all the assets of Femco Services, Inc., R&S Propane, Inc. and Webb Dozer Service, Inc. (collectively, Femco), a group of companies located in Lindsay, Oklahoma for $35,991 in cash, of which a portion is subject to a final working capital adjustment, and we recorded goodwill totaling $11,189. Femco provides fluid handling, frac tank rental, propane distribution and fluid disposal services throughout southern central Oklahoma. We included the accounts of Femco in our completion and production services business segment from the date of acquisition. We believe this acquisition expands our presence in the Fayetteville Shale and enhances our completion and production services business in the Mid-continent region.

(xv) Pumpco Services, Inc. (Pumpco):

On November 8, 2006, we acquired Pumpco Services, Inc., a provider of pressure pumping services in the Barnett Shale play of north Texas, which owns and operates a fleet of pressure pumping units. Consideration for the acquisition included $144,635 in cash, net of cash received, and the issuance of 1,010,566 shares of our common stock, which was valued at the closing price listed on the New York Stock Exchange on November 8, 2006. The number of shares issued was negotiated with the seller, a related party. A fairness opinion was obtained from a third-party as to the value assigned to the common stock of Pumpco, which was used by us to negotiate the purchase price. In addition, Pumpco had debt outstanding of approximately $30,250 at the time of the acquisition. We recorded goodwill totaling $148,551 associated with this acquisition. We included the accounts of Pumpco in our completion and production services business segment from the date of acquisition. This acquisition allowed us to enter the pressure pumping business in the active Barnett Shale region of north Texas. In 2007, we reclassified $2,017 of the goodwill associated with the Pumpco acquisition to identifiable intangible assets and began amortizing this cost over the estimated lives of the related intangible assets. In addition, we reduced the goodwill balance by an additional $3,136 related to deferred tax liabilities which were deemed no longer necessary based on our 2006 tax return filings in 2007.

Results for each of these acquisitions have been included in our accounts and results of operations since the date of acquisition. The following tables summarize the purchase price allocations as of December 31, 2006 by geographic area, as indicated.

Texas US:	**CHB**	**Pinnacle**	**Anderson**	**SMI**	**Brothers**	**Pumpco**	**Totals**
Net assets acquired:							
Property, plant and equipment	$ 4,319	$ 31,452	$ 2,842	$ 169	$ 4,201	$ 45,976	$ 88,959
Non-cash working capital				564	(424)	5,441	5,581
Intangible assets	332	275	4	393	300	1,000	2,304
Deferred tax liabilities						(4,659)	(4,659)
Goodwill	8087	1,049	7,914	1,774	2,859	148,551	170,234

Net assets acquired	$ 12,738	$ 32,776	$ 10,760	$ 2,900	$ 6,936	$ 196,309	$ 262,419
Consideration:							
Cash, net of cash and cash equivalents acquired	$ 12,738	$ 32,776	$ 10,760	$ 2,900	$ 6,936	$ 144,635	$ 210,745
Debt assumed in acquisition						30,250	30,250
Common stock issued for acquisition (1,010,566 shares)						21,424	21,424
Total consideration	$ 12,738	$ 32,776	$ 10,760	$ 2,900	$ 6,936	$ 196,309	$ 262,419

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Notes to Consolidated Financial Statements (Continued)

Mid-continent US:	**Arkoma**	**Turner**	**Airfoam**	**Rosel**	**Femco**	**Totals**
Net assets acquired:						
Property, plant and equipment	$ 6,099	$ 31,313	$ 4,829	$ 5,615	$ 20,226	$ 68,082
Non-cash working capital	2,496	6,914		379	4,426	14,215
Intangible assets	414	55	175	341	150	1,135
Deferred tax liabilities				(1,845)		(1,845)
Goodwill	8,993	16,046	3,115	7,997	11,189	47,340
Net assets acquired	$ 18,002	$ 54,328	$ 8,119	$ 12,487	$ 35,991	$ 128,927
Consideration:						
Cash, net of cash and cash equivalents acquired	$ 18,002	$ 54,328	$ 8,119	$ 11,953	$ 35,991	$ 128,393
Debt assumed in acquisition				534		534
Total consideration	$ 18,002	$ 54,328	$ 8,119	$ 12,487	$ 35,991	$ 128,927

	Rocky Mountains US				**Canada**	
Other:	**Outpost**	**KCL**	**DFS**	**Jim Lee**	**Quinn**	**Totals**
Net assets acquired:						
Property, plant and equipment	$ 4,297	$ 225	$ 200	$ 1,008	$ 4,066	$ 9,796
Non-cash working capital	(225)				45	(180)
Intangible assets	122	53	53	150	518	896
Goodwill	2,348	1,847	1,872	3,842	4,247	14,156
Net assets acquired	$ 6,542	$ 2,125	$ 2,125	$ 5,000	$ 8,876	$ 24,668
Consideration:						
Cash, net of cash and cash equivalents acquired	$ 6,542	$ 2,125	$ 2,125	$ 5,000	$ 8,876	$ 24,668

Overall Summary:	**Texas**	**Mid-Continent**	**Rocky Mountains**	**Canada**	**Totals**
Net assets acquired:					
Property, plant and equipment	$ 88,959	$ 68,082	$ 5,730	$ 4,066	$ 166,837
Non-cash working capital	5,581	14,215	(225)	45	19,616
Intangible assets	2,304	1,135	378	518	4,335

Deferred tax liabilities	(4,659)	(1,845)			(6,504)
Goodwill	170,234	47,340	9,909	4,247	231,730
Net assets acquired	$ 262,419	$ 128,927	$ 15,792	$ 8,876	$ 416,014
Consideration:					
Cash, net of cash and cash equivalents acquired	$ 210,745	$ 128,393	$ 15,792	$ 8,876	$ 363,806
Debt assumed in acquisition	30,250	534			30,784
Common stock issued for acquisition (1,010,566 shares)	21,424				21,424
Total consideration	$ 262,419	$ 128,927	$ 15,792	$ 8,876	$ 416,014

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(c) Acquisitions During the Year Ended December 31, 2005:

(i) The Combination:

On September 12, 2005, IPS, later renamed Complete Production Services, Inc., acquired all of the interest of the minority stockholders in CES and IEM in conjunction with the Combination. The Combination was accounted for using the continuity of interest method as described in Note 1. The purchase of the interest of the minority stockholders by IPS was accounted for using the purchase method of accounting. The purchase resulted in goodwill of $93,792, which represented the excess of the purchase price over the carrying value of the net assets acquired.

The following table summarizes the acquisition of the interest of minority stockholders of CES and IEM in exchange for shares of our common stock and the elimination of the historical amounts reflected in the combined group:

	CES	IEM	Total
Common stock to minority interest	$ 129,718	$ 13,167	$ 142,885
Minority interest in fair value of net assets acquired	44,565	4,528	49,093
Amount recorded as goodwill	$ 85,153	$ 8,639	$ 93,792

Since this transaction represents the purchase of a minority interest in the combined entity, assets and liabilities were deemed to be recorded at historical cost which approximated fair value. Therefore, we recorded an increase in additional paid-in capital with a similar increase in goodwill, with no other changes to asset or liability accounts.

(ii) Post-Combination Acquisitions (After September 12, 2005):

(a) Spindletop Production Services, Ltd. (Spindletop):

On September 29, 2005, we acquired all of the assets of Spindletop, an entity owned by a related party, for $237 in cash, and 90,364 shares of our common stock valued at $11.66 per share, or an aggregate of $1,053, in a transaction accounted for as a purchase. This business consists of a manufacturing and equipment repair operation located in Gainsville, Texas, which produces completion products to be sold through our supply stores, distributors and direct sales force, builds drilling rigs and refurbishes and repairs drilling rigs and well service rigs. Spindletop has a primary service area of the Barnett Shale region of north Texas. The results of operations for this business were included in our accounts from the date of acquisition. Goodwill of $613 resulted from the acquisition and was allocated entirely to the product sales segment.

(b) Big Mac Tank Trucks, Inc. and Affiliates (Big Mac):

On November 1, 2005, we acquired all of the outstanding equity interests of the Big Mac group of companies (Big Mac Transports, LLC, Big Mac Tank Trucks, LLC and Fugo Services, LLC) for $40,800 in cash. Big Mac is based in McAlester, Oklahoma, and provides fluid handling services primarily to customers in eastern Oklahoma and western

Arkansas. The purchase price was adjusted for actual working capital and reimbursable capital expenditures during 2006 resulting in a reduction of goodwill of $528. Goodwill resulting from this transaction was allocated entirely to the completion and production services business segment. We included the operating results of Big Mac in the completion and production services business segment from the date of acquisition. We believe that this acquisition provided a platform to enter the eastern Oklahoma market and new Fayetteville Shale play in Arkansas.

(c) Wolsey Well Service, LP (Wolsey):

On December 15, 2005, we acquired the well servicing assets of Wolsey, a well operating company with a fleet of five well servicing rigs based in Bowie, Texas, for $6,500 in cash. Of the total purchase price, $3,500 was

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

allocated to property, plant and equipment. Goodwill of $3,000 resulted from this transaction and has been allocated entirely to the completion and production services business segment. The results of operations of Wolsey were included in the completion and production services business segment since the date of acquisition.

Results for each of these acquisitions have been included in our accounts and results of operations since the date of acquisition. The following table summarizes the purchase price allocations for these 2005 post-Combination acquisitions as of December 31, 2005:

Post-Combination 2005	**Spindletop**	**Big Mac**	**Wolsey**	**Totals**
Net assets acquired:				
Property, plant and equipment	$ 686	$ 11,715	$ 3,500	$ 15,901
Non-cash working capital	(9)	4,833		4,824
Intangible assets				
Goodwill	613	23,724	3,000	27,337
Net assets acquired	$ 1,290	$ 40,272	$ 6,500	$ 48,062
Consideration:				
Cash, net of cash and cash equivalents acquired	$ 237	$ 40,272	$ 6,500	$ 47,009
Issuance of common stock	1,053			1,053
Consideration	$ 1,290	$ 40,272	$ 6,500	$ 48,062

The price for common shares was based on internal calculations of the fair value for such shares.

(iii) Pre-Combination 2005 Acquisitions (Before September 12, 2005):

(a) Parchman Energy Group, Inc. (Parchman):

On February 11, 2005, we acquired all of the common shares of Parchman in a business combination accounted for as a purchase. Parchman performs coiled tubing services, well testing services, snubbing services and wireline services in Louisiana, Texas, Wyoming and Mexico. The results of operations for Parchman were included in our accounts from the date of acquisition. In addition, the purchase agreement provided for the issuance of up to 1,000,000 shares of our common stock as contingent consideration over the period from the date of acquisition to December 31, 2005 based on our operating results for operations in the United States. These shares were issued in March 2006 at a share value that approximated our initial public offering price, resulting in additional goodwill on the transaction. Goodwill at the date of closing was $20,255 and was allocated entirely to the completion and production services segment. Intangible assets included customer relationships and patents that are being amortized over a 3-to-5 year period. We awarded 344,664 shares of non-vested restricted common stock to certain former Parchman employees, which vest over a three-year term. These restricted shares vested on or before December 31, 2007 or were forfeited. We expensed amounts associated with these restricted shares of $426, $630 and $980 for the years ended December 31, 2007, 2006 and 2005, respectively.

(b) Premier Integrated Technologies (Premier):

On January 1, 2005, we acquired a 50% interest in Premier in a business combination accounted for as a purchase. Premier provides optimization services in Alberta, British Columbia and Saskatchewan. We consolidate Premier, including results of operations, in our accounts from the date of acquisition and have recorded the minority interest ownership. Goodwill of $997 resulted from this acquisition and was allocated entirely to the completion and production services segment. On December 31, 2007, we acquired the remaining 50% interest in Premier, resulting in a decrease in goodwill of $595.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

(c) Roustabout Specialties Inc. (RSI):

On July 7, 2005, we acquired all of the common shares of RSI in a business combination accounted for as a purchase. RSI is a field services and rental company headquartered in Grand Junction, Colorado, with a primary service area of operation in the Piceance Basin of western Colorado. The results of operations for RSI were included in our accounts from the date of acquisition. Goodwill of $3,073 resulted from the acquisition and was allocated entirely to the completion and production services segment.

Results for each of these acquisitions have been included in our accounts and results of operations since the date of acquisition. The following table summarizes the purchase price allocations for these 2005 pre-Combination acquisitions as of December 31, 2005:

Pre-Combination 2005	**Parchman**	**Premier**	**RSI**	**Totals**
Net assets acquired:				
Property, plant and equipment	$ 49,975	$ 2,164	$ 4,900	$ 57,039
Non-cash working capital	1,657	2,390	1,843	5,890
Intangible assets	459			459
Goodwill	20,255	997	3,073	24,325
Long-term debt	(32,017)	(750)		(32,767)
Deferred income taxes	(8,608)	(1,902)		(10,510)
Net assets acquired	$ 31,721	$ 2,899	$ 9,816	$ 44,436
Consideration:				
Cash, net of cash and cash equivalents acquired	$ 9,833	$	$ 8,656	$ 18,489
Subordinated notes	5,000			5,000
Non-cash working capital		1,559		1,559
Property, plant and equipment		1,340		1,340
Issuance of common stock	16,888		1,160	18,048
Consideration	$ 31,721	$ 2,899	$ 9,816	$ 44,436

The price for common shares was based on internal calculations of the fair value for such shares and/or consultations with the seller.

(d) Pro Forma Results:

We calculated the pro forma impact of the businesses we acquired on our operating results for the years ended December 31, 2007 and 2006. The following pro forma results give effect to each of these acquisitions, assuming that each occurred on January 1, 2007 and 2006, as applicable.

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 statements of operations.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

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, 2007	2006
Revenue	$ 1,666,530	$ 1,443,274
Income before taxes and minority interest	$ 257,920	$ 267,810
Net income from continuing operations	$ 164,071	$ 169,597
Earnings per share:		
Basic	$ 2.28	$ 2.58
Diluted	$ 2.24	$ 2.49

4. Accounts receivable:

	2007	2006
Trade accounts receivable	$ 272,115	$ 260,733
Related party receivables(a)	8,823	12,478
Unbilled revenue	41,989	27,096
Notes receivable	3,378	78
Other receivables	8,117	3,810
	334,422	304,195
Allowance for doubtful accounts	5,737	2,431
	$ 328,685	$ 301,764

(a) See Note 21, Related Party Transactions.

The following table summarizes the change in our allowance for doubtful accounts for the years ended December 31, 2007, 2006 and 2005:

	Balance at Beginning	Additions Charged	Write-offs or	Balance at End of

Year Ended		of Period		to Expense		Adjustments		Period
2007	$	2,431	$	7,277	$	(3,971)	$	5,737
2006	$	1,872	$	2,329	$	(1,770)	$	2,431
2005	$	543	$	1,332	$	(3)	$	1,872

5. Inventory:

	2007	2006
Finished goods	$ 49,716	$ 38,877
Manufacturing parts, materials and fuel	9,772	6,772
	59,488	45,649
Inventory reserves	2,420	1,719
	$ 57,068	$ 43,930

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Notes to Consolidated Financial Statements (Continued)

6. Property, plant and equipment:

December 31, 2007	Cost	Accumulated Depreciation	Net Book Value
Land	$ 9,259	$	$ 9,259
Building	17,667	1,545	16,122
Field equipment	1,073,939	244,985	828,954
Vehicles	97,217	22,774	74,443
Office furniture and computers	12,635	4,296	8,339
Leasehold improvements	17,384	1,708	15,676
Construction in progress	81,902		81,902
	$ 1,310,003	$ 275,308	$ 1,034,695

December 31, 2006	Cost	Accumulated Depreciation	Net Book Value
Land	$ 5,816	$	$ 5,816
Building	7,140	840	6,300
Field equipment	746,314	128,553	617,761
Vehicles	63,687	14,152	49,535
Office furniture and computers	9,891	2,712	7,179
Leasehold improvements	12,895	1,164	11,731
Construction in progress	73,381		73,381
	$ 919,124	$ 147,421	$ 771,703

Construction in progress at December 31, 2007 and 2006 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, 2007 and 2006, we recorded capitalized interest of $3,922 and $2,058, 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.

7. Intangible assets:

	As of December 31, 2007			As of December 31, 2006		
	Historical	Accumulated	Net Book	Historical	Accumulated	Net Book

Description	Term (In months)	Cost	Amortization	Value	Cost	Amortization	Value
Patents and trademarks	60 to 120	$ 4,026	$ 937	$ 3,089	$ 2,762	$ 360	$ 2,402
Contractual agreements	24 to 120	10,123	4,413	5,710	6,839	2,564	4,275
Customer lists and other	36 to 60	3,387	1,392	1,995	1,787	699	1,088
Totals		$ 17,536	$ 6,742	$ 10,794	$ 11,388	$ 3,623	$ 7,765

We recorded amortization expense associated with intangible assets of continuing operations totaling $3,121, $1,865 and $1,428 for the years ended December 31, 2007, 2006 and 2005, respectively. We expect to record amortization expense associated with these intangible assets for the next five years approximating: 2008 $3,177; 2009 $2,668; 2010 $2,201; 2011 $1,806; and 2012 $942.

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Notes to Consolidated Financial Statements (Continued)

8. Deferred financing costs:

	Cost	Accumulated Amortization	Net Book Value
December 31, 2007			
Deferred financing costs	$ 16,649	$ 2,455	$ 14,194
December 31, 2006			
Deferred financing costs	$ 16,276	$ 547	$ 15,729

We incurred deferred financing costs during 2006 related to the issuance of our senior notes in December 2006 totaling $13,414 and $718 associated with the amendment of our existing term loan and revolving credit facility.

We assumed the debt of Pumpco upon acquisition on November 11, 2006. In December 2006, we retired all outstanding borrowings under the Pumpco term loan facility and incurred a $170 charge to expense the remaining unamortized deferred financing costs. For the year ended December 31, 2005, we expensed unamortized deferred financing costs totaling $3,315 associated with debt facilities which were retired on September 12, 2005 with the proceeds from our then-existing $580,000 term loan and revolving credit facility.

9. Taxes:

Tax expense (benefit) from continuing operations consisted of:

	2007	2006	2005
Domestic:			
Current income taxes	$ 48,494	$ 43,396	$ 11,653
Deferred income taxes	40,869	29,221	18,557
	89,363	72,617	30,210
Foreign:			
Current income taxes	7,148	3,585	3,469
Deferred income taxes (benefit)	(2,770)	1,686	(564)
	4,378	5,271	2,905
Tax expense continuing operations	$ 93,741	$ 77,888	$ 33,115

We operate in several tax jurisdictions. A reconciliation of the U.S. federal income tax rate of 35% for the years ended December 31, 2007, 2006 and 2005 to our effective income tax rate follows:

	2007	2006	2005
Expected provision for taxes:	$ 89,158	$ 75,293	$ 29,547
Increase (decrease) resulting from foreign tax rate differential	2,626	(1,756)	(59)
Decrease in foreign deferred taxes	(760)		
State taxes, net of federal benefit	6,961	5,486	2,190
Non-deductible expenses	(2,296)	(1,282)	1,169
Other, net	(1,948)	147	268
Tax expense continuing operations	$ 93,741	$ 77,888	$ 33,115

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

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

	2007	2006
Deferred income tax assets:		
Net operating loss	$ 445	$ 686
Intangible assets	3,745	3,080
Stock-based compensation costs	3,843	1,636
	8,033	5,402
Less valuation allowance	(290)	(747)
	7,743	4,655
Deferred income tax liabilities:		
Property, plant and equipment	(121,460)	(85,110)
Goodwill	(10,467)	(7,487)
Other	(4,720)	(2,863)
	(136,647)	(95,460)
Net deferred income tax liability	$ (128,904)	$ (90,805)

The net deferred income tax liability consisted of:

	2007	2006
Domestic	$ (121,138)	$ (80,269)
Foreign	(7,766)	(10,536)
	$ (128,904)	$ (90,805)

Net operating loss carryforwards are included in the determination of our deferred tax asset at December 31, 2007. We will need to generate future taxable income of approximately $1,534 in order to fully utilize our net operating loss carryforwards. We had U.S. loss carryforwards of $1,599 at December 31, 2005 which had been fully utilized as of December 31, 2006. We have a $1,534 foreign non-capital loss carryforward at December 31, 2007, compared to $2,131 at December 31, 2006.

No deferred income taxes were provided on approximately $19,057 of undistributed earnings of foreign subsidiaries as of December 31, 2007, 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 FASB Interpretation No. 48 entitled Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, referred to as FIN 48, as of January 1, 2007. FIN 48 clarifies the accounting for uncertain tax positions that may have been taken by an entity. Specifically, FIN 48 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 FIN 48, if a tax position previously failed the more-

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Notes to Consolidated Financial Statements (Continued)

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.

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 under FIN 48 did not have a material impact on our financial statements during the year ended December 31, 2007. Therefore, we have not recorded an adjustment to our financial statements related to the adoption of FIN 48. We will continue to evaluate our tax positions in accordance with FIN 48, and recognize any future impact under FIN 48 as a charge to income in the applicable period in accordance with the standard. Our tax filings for tax years 2003 to 2006 remain open for examination by taxing authorities.

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 end December 31, 2007, 2006 or 2005.

In May 2007, the FASB issued FASB Staff Position FIN 48-1, an amendment to FIN 48, which provides 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 will apply this guidance going forward, as applicable.

10. Bank operating loans:

At December 31, 2004, we had Canadian and U.S. dollar syndicated revolving operating credit facilities in place. The Canadian operating facility provided up to C$10,000. The U.S. operating facility line provided a revolving credit facility up to $10,000. Interest was on a grid based on certain financial ratios and ranged from prime to prime plus 1.25% per annum. At December 31, 2004, Canadian and U.S. prime were 4.25% and 5.25%, respectively. The facilities were secured by a general security agreement providing a first charge against our assets. The Canadian and U.S. credit facilities included a commitment fee of 0.25% and 0.375% per annum, respectively, on the average unused portion of the revolving credit facilities.

The maximum amounts available under these credit facilities were subject to a borrowing base formula based upon trade accounts receivable and inventory. As at December 31, 2004, the maximum available under these combined facilities was limited by the borrowing base formula to $20,536.

At December 31, 2004, we had drawn $15,745 on these operating lines and an additional amount of $6,000 outstanding pursuant to an overnight facility in the United States offset by a corresponding $6,000 of cash on deposit in Canada. As at December 31, 2004, $48 of letters of credit were outstanding.

On September 12, 2005, we retired all amounts outstanding under these bank operating loans with proceeds from borrowings under a $580,000 term loan and revolving credit facility. See Note 12, Long-term Debt.

11. Notes payable:

On January 5, 2006, we entered into a note agreement with our insurance broker to finance our annual insurance premiums for the policy year beginning December 1, 2005 through November 30, 2006. As of

COMPLETE PRODUCTION SERVICES, INC.

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December 31, 2005, we recorded a note payable totaling $14,584 and an offsetting prepaid asset which included a broker s fee of $600. We amortized the prepaid asset to expense over the policy term, and incurred finance charges totaling $268 as interest expense related to this arrangement during 2006. This policy was renewed for the policy term beginning December 1, 2006 through November 30, 2007, pursuant to which we recorded a note payable and an offsetting prepaid asset totaling $17,087 as of December 31, 2006, which included a broker s fee of approximately $600. Of this liability, $10,190 was paid on January 5, 2007, and the remainder was paid during the policy term. We entered into a new arrangement to finance our annual insurance premiums for the policy term beginning December 1, 2007 and extending through April 30, 2009. As of December 31, 2007, we recorded a note payable totaling $15,354 and an offsetting prepaid asset which included a broker s fee of approximately $625. Of this prepaid asset, $3,257 was recorded as a long-term asset at December 31, 2007. We expect to incur a finance fee of $289 related to this policy renewal and to repay this note payable prior to December 31, 2008.

12. Long-term debt:

The following table summarizes long-term debt as of December 31, 2007 and 2006:

	2007	2006
U.S. revolving credit facility(a)	$ 160,000	$ 78,668
Canadian revolving credit facility(a)	12,219	17,575
8% senior notes(b)	650,000	650,000
Subordinated seller notes(c)	3,450	3,450
Capital leases and other(d)	993	1,948
	826,662	751,641
Less: current maturities of long-term debt and capital leases	675	1,064
	$ 825,987	$ 750,577

(a) Concurrent with the consummation of the Combination on September 12, 2005, we entered into a credit agreement related to a syndicated senior secured credit facility (the Credit Facility) pursuant to which all bank debt held by IPS, CES and IEM was repaid and replaced with the proceeds from the Credit Facility. The Credit Facility was comprised of a $420,000 term loan credit facility that was to mature in September 2012, a U.S. revolving credit facility of $130,000 that was to mature in September 2010, and a Canadian revolving credit facility of $30,000 that was to mature in September 2010. Interest on the Credit Facility was to be determined by reference to the London Inter-bank Offered Rate (LIBOR) plus a margin of 1.25% to 2.75% (depending on the ratio of total debt to EBITDA, as defined in the agreement) for revolving advances and a margin of 2.75% for term loan advances. Interest on advances under the Canadian revolving facility was to be calculated at the Canadian Prime Rate plus a margin of 0.25% to 1.75%. Quarterly principal repayments of 0.25% of the original principal amount were required for the term loans, which commenced in December 2005. The agreement governing the Credit Facility contains covenants restricting the levels of certain transactions including: entering into certain loans, the granting of certain liens, capital expenditures, acquisitions, distributions to stockholders, certain asset dispositions and operating leases. The Credit Facility is secured by substantially all of our assets.

On March 29, 2006, our lenders amended and restated the agreement governing the Credit Facility to provide for, among other things: (1) an increase in the amount of the U.S. revolving credit facility to $170,000 from $130,000; (2) an increase in the level of capital expenditures permitted under the agreement for the years ended December 31, 2006 and 2007; (3) a waiver of the requirement to prepay up to $50,000 of term debt using the first $100,000 of proceeds from an equity offering in 2006; and (4) a reduction in the Eurocurrency margin on the term loan to LIBOR plus 2.50%. In addition, at any time prior to the maturity of the facility, and as long as no default or event of default has occurred (and is continuing), we had the right to increase the aggregate

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commitments under the amended Credit Facility agreement by a total of up to $150,000, subject to receiving commitments from one or more lenders totaling this amount. On October 20, 2006, we exercised the accordion feature of our Credit Facility and received authorization from our lenders to increase the commitment of our U.S. revolving credit facility from $170,000 to $310,000 and to increase the commitment of our Canadian revolving credit facility from $30,000 to $40,000. There were no other significant modifications to the terms or restrictive debt covenants of our Credit Facility at that time.

On April 28, 2006, we repaid all outstanding borrowings under our U.S. revolving credit facility using a portion of the proceeds from our initial public offering totaling $127,500. See Note 14, Stockholders Equity. Subsequently, we borrowed and repaid amounts under the swingline portion of this U.S. revolving facility, resulting in a net borrowing of $160,000 as of December 31, 2007.

On December 6, 2006, we amended and restated our existing senior secured credit facility (the Credit Agreement) with Wells Fargo Bank, National Association, as U.S. Administrative Agent, and certain other financial institutions. The Credit Agreement provided for a $310,000 U.S. revolving credit facility that matures in 2011 and a $40,000 Canadian revolving credit facility (with Integrated Production Services, Ltd., one of our wholly-owned subsidiaries, as the borrower thereof) that matures in 2011. In addition, certain portions of the credit facilities are available to be borrowed in U.S. Dollars, Canadian Dollars, Pounds Sterling, Euros and other currencies approved by the lenders.

On October 19, 2007, we amended and restated the Credit Agreement with Wells Fargo Bank, National Association, as U.S. Administrative Agent, and certain other financial institutions, to increase the U.S revolving credit facility to $360,000 and to include a provision for a commitment increase clause, as defined in the Credit Agreement, which permits us to effect up to two separate increases in the aggregate commitments under the facility by designating a participating lender to increase its commitment, by mutual agreement, in increments of at least $50,000, with the aggregate of such commitment increases not to exceed $100,000, and in accordance with other provisions as stipulated in the amendment.

Subject to certain limitations, we have the ability to elect how interest under the Credit Agreement will be computed. Interest under the Credit Agreement may be determined by reference to (1) the London Inter-bank Offered Rate, or LIBOR, plus an applicable margin between 0.75% and 1.75% per annum (with the applicable margin depending upon our ratio of total debt to EBITDA (as defined in the agreement)), or (2) the Base Rate (i.e., the higher of the Canadian bank s prime rate or the CDOR rate plus 1.0%, in the case of Canadian loans or the greater of the prime rate and the federal funds rate plus 0.5%, in the case of U.S. loans), plus an applicable margin between 0.00% and 0.75% per annum. If an event of default exists under the Credit Agreement, advances will bear interest at the then-applicable rate plus 2%. Interest is payable quarterly for base rate loans and at the end of applicable interest periods for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest will be paid at the end of each three-month period.

The Credit Agreement also contains various covenants that limit our and our subsidiaries ability to: (1) grant certain liens; (2) make certain loans and investments; (3) make capital expenditures; (4) make distributions; (5) make acquisitions; (6) enter into hedging transactions; (7) merge or consolidate; or (8) engage in certain asset dispositions. Additionally, the Credit Agreement limits our and our subsidiaries ability to incur additional indebtedness if: (1) we are not in pro forma compliance with all terms under the Credit Agreement, (2) certain covenants of the additional indebtedness are more onerous than the covenants set forth in the Credit Agreement, or (3) the additional indebtedness provides for amortization, mandatory prepayment or repurchases of senior unsecured or subordinated debt during the duration of the Credit Agreement with certain exceptions. The Credit Agreement also limits additional secured debt to 10% of our consolidated net worth (i.e., the excess of our assets over the sum of our liabilities plus the minority interests). The Credit Agreement contains covenants which, among other things, require us and our subsidiaries, on a consolidated basis, to maintain specified ratios or conditions as follows (with such ratios tested at the end of each fiscal quarter): (1) total debt to EBITDA, as defined in the Credit Agreement, of not more than 3.0 to 1.0; and (2) EBITDA, as defined, to total interest

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

expense of not less than 3.0 to 1.0. We were in compliance with all debt covenants under the amended and restated Credit Agreement as of December 31, 2007.

Under the Credit Agreement, we are permitted to prepay our borrowings.

All of the obligations under the U.S. portion of the Credit Agreement are secured by first priority liens on substantially all of 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 Credit Agreement are guaranteed by substantially all of our U.S. subsidiaries. All of the obligations under the Canadian portions of the Credit Agreement are secured by first priority liens on substantially all of the assets of our subsidiaries. Additionally, all of the obligations under the Canadian portions of the Credit Agreement are guaranteed by us as well as certain of our subsidiaries.

If an event of default exists under the Credit Agreement, as defined therein, the lenders may accelerate the maturity of the obligations outstanding under the Credit Agreement and exercise other rights and remedies. While an event of default is continuing, advances will bear interest at the then-applicable rate plus 2%.

All borrowings outstanding under the term loan portion of the amended Credit Agreement bore interest at 7.66% through 2006 until the term loan was retired in December 2006. There were no borrowings outstanding under the term loan portion of the facility at December 31, 2007. Borrowings under the U.S. revolving facility bore interest at rates ranging from 6.45% to 7.50% and the Canadian revolving credit facility bore interest at 6.25% at December 31, 2007. For the years ended December 31, 2007 and 2006, the weighted average interest rates on average borrowings under the amended Credit Facility were approximately 6.56% and 7.48%, respectively. There were letters of credit outstanding under the U.S. revolving portion of the facility totaling $37,929 which reduced the available borrowing capacity as of December 31, 2007. We incurred fees of 1.25% of the total amount outstanding under letter of credit arrangements through December 31, 2007. Our available borrowing capacity under the U.S. and Canadian revolving facilities at December 31, 2007 was $162,071 and $27,780, respectively.

(b) On December 6, 2006, we issued 8.0% senior notes with a face value of $650,000 through a private placement of debt. The 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, commencing 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; and (5) 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. We can redeem 35% of these notes on or before December 15, 2009 using the proceeds of certain equity offerings. 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. We used the net proceeds from this note issuance to repay all outstanding borrowings under the term loan portion of our credit facility which totaled approximately $415,800, to repay all of the outstanding indebtedness assumed in connection with the acquisition of Pumpco which totaled approximately $30,250 and to repay approximately $192,000 of the outstanding indebtedness under the U.S. revolving credit portion of the credit facility. On June 15, 2007 and December 15, 2007, we paid $27,300 and $26,000, respectively, in connection with our scheduled semi-annual interest payments pursuant to these notes.

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 Securities and Exchange Commission which enabled these holders to exchange their notes for publicly registered notes with substantially identical terms. These holders exchanged 100% of these 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.

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Notes to Consolidated Financial Statements (Continued)

(c) On February 11, 2005, we issued subordinated notes totaling $5,000 to certain sellers of Parchman common shares in connection with the acquisition of Parchman. These notes were unsecured, subordinated to all present and future senior debt and bore interest at 6.0% during the first three years of the note, 8.0% during year four and 10.0% thereafter. The notes matured in early May 2006. On May 3, 2006, we repaid all principal and accrued interest outstanding pursuant to these note agreements totaling $5,029.

We issued subordinated seller notes totaling $3,450 in 2004 related to certain business acquisitions. These notes bear interest at 6% and mature in March 2009.

(d) Included in other outstanding debt at December 31, 2007 was: (1) capital leases totaling $224 which are collateralized by specific assets and bear interest at various rates averaging approximately 10% for the years ended December 31, 2007 and 2006; (2) a $205 mortgage loan related to property in Wyoming, which requires annual principal payments of approximately $60, accrues interest at 6.0% and matures in 2012; and (3) loans totaling $564 related to equipment purchases with terms of 12 to 60 months and extending through September 2010.

At December 31, 2007, principal maturities under our long-term debt facilities (including capital leases) for the next five years were: 2008 $675; 2009 $3,659; 2010 $84; 2011 $172,244; and 2012 $0. Our senior notes mature in 2016, at a face value of $650,000.

13. Convertible debentures:

On May 31, 2000, IPSL, one of our wholly-owned subsidiaries, issued convertible debentures of C$5,000 to mature June 30, 2005 and convertible into 627,408 shares of common stock at the holders option at C$7.97 per share at any time prior to maturity. The debentures were secured by a general security agreement providing a charge against IPSL s assets, subordinated to any other senior indebtedness, and bore interest at 9% per annum. The chief executive officer of the debenture holder was a director of the subsidiary. The debenture was repaid in full on June 30, 2005.

14. Stockholders equity:

On September 12, 2005, we completed the Combination of CES, IPS and IEM pursuant to which CES and IEM stockholders exchanged all of their common stock for common stock of IPS. The CES stockholders received 19.704 shares of IPS common stock for each share of CES, and the IEM stockholders received 19.410 shares of IPS common stock for each share of IEM. Subsequent to the combination, IPS changed its name to Complete Production Services, Inc. In the Combination, the former CES stock was converted into approximately 57.6% of our common stock, the IPS stock remained outstanding and represented approximately 33.2% of our common stock and the former IEM stock was converted into approximately 9.2% of our common shares. The amounts of authorized and issued stock, warrants and options of CES were adjusted to reflect the exchange ratio of 19.704 per share pursuant to the Combination. The amounts of authorized and issued stock, warrants and options of IEM were adjusted to reflect the exchange ratio of 19.410 per share pursuant to the Combination.

(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) Stock Split:

On December 29, 2005, we effected a 2-for-1 split of common stock. As a result, all common stock and per share data, as well as data related to other securities including stock warrants, restricted stock and stock options, were adjusted retroactively to give effect to this stock split for all periods presented within the accompanying

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

financial statements, except par value which remained at $0.01 per share, resulting in an insignificant reclassification between common stock and additional paid-in capital.

(c) Dividend:

On September 12, 2005, we paid a dividend of $2.62 per share for an aggregate payment of approximately $146,900 to stockholders of record on that date. We were also obligated to issue up to an aggregate of approximately 1,200,000 shares of our common stock as contingent consideration based on certain operating results of companies that we had previously acquired and we made additional cash payments of $3,100 in respect of such contingent shares ultimately issued in the amount of the dividend that would have been paid on such shares if those shares had been issued prior to the payment of the dividend.

(d) 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. We used approximately $127,500 of the proceeds from this offering to retire principal and interest outstanding under the U.S. revolving credit facility as of April 28, 2006. Of the remaining funds, approximately $165,000 was invested in tax-free or tax-advantaged municipal bond funds and similar financial instruments with a term of less than one year. We liquidated these short-term investments during 2006 to purchase capital assets, to acquire complementary businesses and for other general corporate purposes. We considered our short-term investments as held for sale in accordance with SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities, as they did not appreciate or depreciate with changes in market value but rather provided only investment income.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

The following table summarizes the pro forma impact of our initial public offering on earnings per share for the years ended December 31, 2006 and 2005, assuming the 13,000,000 shares had been issued on January 1, 2005. No pro forma adjustments have been made to net income as reported.

	For the Year Ended December 31, 2006	For the Year Ended December 31, 2005
Net income as reported	$ 139,086	$ 53,862
Basic earnings per share, as reported:		
Continuing operations	$ 2.09	$ 1.09
Discontinued operations	$ 0.02	$ 0.07
	$ 2.11	$ 1.16
Basic earnings per share, pro forma:		
Continuing operations	$ 1.97	$ 0.85
Discontinued operations	$ 0.02	$ 0.05
	$ 1.99	$ 0.90
Diluted earnings per share, as reported:		
Continuing operations	$ 2.02	$ 1.00
Discontinued operations	$ 0.02	$ 0.06
	$ 2.04	$ 1.06
Diluted earnings per share, pro forma:		
Continuing operations	$ 1.91	$ 0.80
Discontinued operations	$ 0.02	$ 0.05
	$ 1.93	$ 0.85

(e) Stock-based Compensation:

We maintain each of the option plans previously maintained by IPS, CES and IEM. Under the three option plans, stock-based compensation could be granted to employees, officers and directors to purchase up to 2,540,485 common shares, 3,003,463 common shares and 986,216 common shares, respectively. The exercise price of each option is based on the fair value of the individual company s 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.

We adopted SFAS No. 123R on January 1, 2006. This pronouncement requires that 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.

(i) Employee Stock Options Granted Prior to September 30, 2005:

As required by SFAS No. 123R, we continue to account for stock-based compensation for grants made prior to September 30, 2005, the date of our initial filing with the Securities and Exchange Commission, using the intrinsic value method prescribed by APB No. 25, 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.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

(ii) 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 (prior to adoption of SFAS No. 123R), we have utilized the modified prospective transition method to record expense associated with these stock-based compensation instruments. Under this transition method, we did not record compensation expense associated with these stock option grants during the period October 1, 2005 through December 31, 2005. The pro forma impact of applying the fair value methodology prescribed by SFAS No. 123 for these grants during the period October 1, 2005 through December 31, 2005, would have been a decrease in net income of $39, with no impact on diluted earnings per share as presented. This pro forma impact was 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.

Beginning January 1, 2006, upon adoption of SFAS No. 123R, we began to recognize expense related to these option grants over the applicable vesting period. For the years ended December 31, 2007 and 2006, the compensation expense recognized related to these stock options was $307 for each year, which reduced net income by $200 and $195, respectively. There was no impact on basic and diluted earnings per share from continuing operations as reported for the years ended December 31, 2007 and 2006 attributable to the compensation expense recognized related to these stock options. The unrecognized compensation costs related to the non-vested portion of these awards was $270 as of December 31, 2007, and will be recognized over the remaining term of the respective three-year vesting periods.

(iii) 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 under SFAS No. 123R, 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, 2007 and 2006, the Compensation Committee of our Board of Directors authorized the grant of 925,700 and 1,008,900 employee stock options, respectively, 56,800 and 64,800 non-vested restricted shares issuable to our officers and employees, respectively, and 38,268 non-vested restricted shares issuable in connection with an acquisition in September 2006. These stock options and non-vested shares were issued pursuant to this authorization in the respective years. In addition, 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. Upon exercise of these Pumpco stock options, we will issue shares of our common stock. Stock option grants in 2007 had an exercise price which ranged from $17.67 to $27.11 per share. The stock option grants in 2006 had an exercise price which ranged from $5.00 to $24.00 per share. The exercise price represented the fair market value of the shares on the date of grant, except for the Pumpco shares issued at $5.00 per share in November 2006, which were issued below market price pursuant to the agreed-upon conversion rate negotiated as part of the acquisition. These stock option grants vest ratably over a three- to four-year term. Additionally, the directors received grants of stock based compensation during 2007, which included 40,000 stock options that vest ratably over a three-year period, and 17,144 shares of non-vested restricted stock that vest 100% on May 24, 2008, one year from the date of grant. During 2006, grants to the directors included 40,000 options that vest ratably over a four-year term and 16,672 shares of non-vested restricted stock that vested on April 26, 2007. The weighted average fair values of 2007 and 2006 stock option grants were $6.14 and $9.46 per share, respectively. The fair value of this stock-based compensation was determined by applying a Black-Scholes option pricing model based on the following assumptions:

Assumptions:	**For the Year Ended December 31, 2007**	**2006**
Risk-free rate	4.16% to 4.98%	4.73% to 5.02%
Expected term (in years)	2.2 to 5.1	2.1 to 5.1
Volatility	29% to 38%	37% to 38%
Calculated fair value per option	$4.21 to $9.33	$5.51 to $16.67

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

We completed our initial public offering in April 2006. Therefore, we did not have sufficient historical market data in order to determine the volatility of our common stock. In accordance with the provisions of SFAS No. 123R, 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 options granted during the years ended December 31, 2007 and 2006.

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 $13,703 related to our stock option grants made after January 1, 2006. For the years ended December 31, 2007 and 2006, we have recognized expense related to these stock option grants totaling $4,118 and $1,498, respectively, which represents a reduction of net income before taxes and minority interest. The impact on net income was a reduction of $2,677 and $956, respectively. The unrecognized compensation costs related to the non-vested portion of these awards was $7,948 as of December 31, 2007 and will be recognized over the applicable remaining vesting periods.

The following table summarizes the impact of the adoption of SFAS No. 123R on our results of operations and cash flows for the years ended December 31, 2007 and 2006:

Account Description	**Effect of Adoption of SFAS No. 123R**
Year Ended December 31, 2007:	
Income from continuing operations	Decrease of $2,876
Income before taxes	Decrease of $4,425
Net income	Decrease of $2,876
Cash flows from operating activities	Decrease of $6,662
Cash flows from financing activities	Increase of $6,662
Earnings per share:	
Basic	Decrease of $0.04 per share
Diluted	Decrease of $0.04 per share
Year Ended December 31, 2006:	
Income from continuing operations	Decrease of $1,179
Income before taxes	Decrease of $1,848
Net income	Decrease of $1,179
Cash flows from operating activities	Decrease of $2,333
Cash flows from financing activities	Increase of $2,333
Earnings per share:	
Basic	Decrease of $0.02 per share
Diluted	Decrease of $0.02 per share

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 2007 and 2006 grants to officers and employees totaling $1,600 and $1,555, respectively, over the three-year vesting period, our grants to directors in 2007 and 2006 totaling $450 and $400, respectively, over a twelve-month vesting period, and our 2006 grants in connection with acquisitions totaling $1,364 over a twenty-four month vesting period.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

The following tables provide a roll forward of stock options from December 31, 2004 to December 31, 2007 and a summary of stock options outstanding by exercise price range at December 31, 2007:

	Options Outstanding	
	Number	Weighted Average Exercise Price
Balance at December 31, 2004	2,259,396	$ 3.60
Granted	1,746,309	$ 7.39
Exercised	(15,082)	$ 4.11
Cancelled	(478,179)	$ 4.15
Balance at December 31, 2005	3,512,444	$ 5.42
Granted	1,008,900	$ 21.19
Exercised	(506,406)	$ 3.52
Cancelled	(150,378)	$ 8.41
Balance at December 31, 2006	3,864,560	$ 9.67
Granted	925,700	$ 20.19
Exercised	(934,095)	$ 4.40
Cancelled	(125,404)	$ 17.06
Balance at December 31, 2007	3,730,761	$ 13.36

	Options Outstanding			Options Exercisable		
Range of Exercise Price	Outstanding at December 31, 2007	Weighted Average Remaining Life (Months)	Weighted Average Exercise Price	Exercisable at December 31, 2007	Weighted Average Remaining Life (months)	Weighted Average Exercise Price
$2.00	238,127	17	$ 2.00	238,127	17	$ 2.00
$4.48 - $4.80	506,666	22	$ 4.70	386,250	20	$ 4.67
$5.00	267,727	44	$ 5.00	207,231	38	$ 5.00
$6.69	622,666	87	$ 6.69	313,825	87	$ 6.69
$11.66	434,838	93	$ 11.66	274,415	93	$ 11.66
$17.60 - $19.87	847,200	109	$ 19.83	3,000	106	$ 18.39
$22.55 - $24.07	768,537	100	$ 23.96	245,459	100	$ 23.97

$26.26 - $27.11	45,000	104	$	26.35				
	3,730,761	79	$	13.36	1,668,307	59	$	8.72

The total intrinsic value of stock options exercised during the years ended December 31, 2007 and 2006 was $16,636 and $8,983, respectively. The total intrinsic value of all vested outstanding stock options at December 31, 2007 was $15,426. Assuming all stock options outstanding at December 31, 2007 were vested, the total intrinsic value of all outstanding stock options would have been $17,211.

(f) Amended and Restated 2001 Stock Incentive Plan:

On March 28, 2006, our Board of Directors approved an amendment to the 2001 Stock Incentive Plan which increased the maximum number of shares issuable under the plan to 4,500,000 from 2,540,485, pursuant to which we could grant up to 1,959,515 additional shares of stock-based compensation, as of that date, to our directors,

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

officers and employees. On April 12, 2006, stockholders owning more than a majority of the shares of our common stock adopted the amendment to the 2001 Stock Incentive Plan.

(g) Non-vested Restricted Stock:

In accordance with SFAS No. 123R, we do not present deferred compensation as a contra-equity account, but rather present the amortization of non-vested restricted stock as an increase in additional paid-in capital. At December 31, 2007 and 2006, amounts not yet recognized related to non-vested stock totaled $2,977 and $4,151, respectively, which represented the unamortized expense associated with awards of non-vested stock granted to employees, officers and directors under our compensation plans, including $1,248 and $2,188 related to grants made in 2007 and 2006, respectively. 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 $3,142, $2,738 and $1,751 for the years ended December 31, 2007, 2006 and 2005, respectively.

The following table summarizes the change in non-vested restricted stock from December 31, 2004 to December 31, 2007:

	Non-vested Restricted Stock	
	Number	Weighted Average Grant Price
Balance at December 31, 2004	301,982	$ 3.33
Granted	637,924	$ 7.03
Vested	(153,736)	$ 6.36
Balance at December 31, 2005	786,170	$ 5.74
Granted	145,643	$ 22.79
Vested	(213,996)	$ 7.53
Forfeited	(27,744)	$ 8.39
Balance at December 31, 2006	690,073	$ 8.67
Granted	96,254	$ 21.30
Vested	(156,944)	$ 12.93
Forfeited	(3,512)	$ 23.50
Balance at December 31, 2007	625,871	$ 9.46

(h) Common Shares Issued for Acquisitions:

In accordance with the agreements relating to the acquisitions of Parchman and MGM Well Services, Inc., entered into in February 2005 and December 2004, respectively, we issued 1,000,000 shares and 164,210 shares, respectively, to the former owners of these companies during the first quarter of 2006, based upon our operating results. As a result of these issuances, we recorded common stock and additional paid-in capital totaling $27,359 with a corresponding increase in goodwill.

On November 8, 2006, we issued 1,010,566 shares of our common stock as purchase consideration for Pumpco. See Note 21, Related Party Transactions. In connection with this issuance, we recorded common stock and additional paid-in capital totaling $21,424, an issuance price of $21.20 per share which was the closing price of our common stock on November 8, 2006. The number of shares issued was calculated based upon the determined market value of Pumpco s common stock and the agreed-upon purchase price negotiated with the seller.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

(i) Warrants:

On May 23, 2001, we issued a warrant to our major shareholder, SCF-IV, L.P. (SCF), to purchase up to 4,000,000 shares of our common stock at an exercise price of $5.00 per share any time through May 23, 2011. The warrant was issued as a source of future financing for our growth. In 2001 and 2004, SCF purchased 740,000 shares and 400,000 shares, respectively, under the warrant. On February 9, 2005, SCF purchased another 2,000,000 shares under the warrant. The warrant was cancelled on September 12, 2005.

In August 2004, we issued a warrant to SCF to purchase up to 6,211,200 shares of our common stock at an exercise price of $2.58 per share at any time through August 31, 2007 and a warrant to one of our minority stockholders to purchase up to 970,500 shares of our common stock at an exercise price of $2.58 per share at any time through August 31, 2007. These warrants were cancelled on September 12, 2005.

Pursuant to a then-existing subordinated credit agreement at IEM, we issued detachable warrants to the lenders to purchase up to 71,818 shares of our common stock at $2.58 per share at any time through August 31, 2007. These warrants were cancelled on September 12, 2005. In addition, we issued detachable warrants to our lenders under the subordinated credit agreement to purchase up to 48,526 shares of our common stock at $0.01 per share at any time through August 31, 2007. The fair value of these warrants, $125,000, was recorded as additional paid-in capital and as a discount on the liability under the subordinate credit agreement. These warrants were exercised on September 12, 2005.

No warrants related to our common stock were outstanding at December 31, 2007 and 2006.

15. 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, non-vested restricted stock, contingent shares, stock warrants and convertible debentures, as determined using the treasury stock method prescribed by SFAS No. 128, 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, 2007, 2006 and 2005:

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Weighted average basic common shares outstanding	71,991	65,843	46,603
Effect of dilutive securities:			
Employee stock options	1,078	1,613	743
Non-vested restricted stock	283	313	486
Contingent shares(a)		306	
Stock warrants(b)			2,824

Weighted average diluted common and potential common shares outstanding	73,352	68,075	50,656

(a) Contingent shares represent potential common stock issuable to the former owners of Parchman and MGM pursuant to the respective purchase agreements based upon 2005 operating results. On March 31, 2006, we calculated and issued the actual shares earned totaling 1,214 shares.

(b) All outstanding stock warrants were exercised or cancelled as of September 12, 2005, the date of the Combination.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

We excluded the impact of anti-dilutive potential common shares from the calculation of diluted weighted average shares for the years ended December 31, 2007, 2006 and 2005. If these potential common shares were included, the impact would have been a decrease in weighted average shares outstanding of 231,233 shares, 41,555 shares and 115,249 shares, respectively, for the years ended December 31, 2007, 2006 and 2005.

16. Discontinued operations:

In August 2006, our Board of Directors authorized and committed to a plan to sell certain manufacturing and production enhancement operations of a subsidiary located in Alberta, Canada, which includes certain assets located in south Texas. 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 in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. We revised our financial statements, pursuant to SFAS No. 144, and reclassified the assets and liabilities of the disposal group 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 from discontinued operations, net of tax, for the accompanying statements of operations for the years ended December 31, 2006 and 2005. We ceased depreciating the assets of this disposal group in September 2006 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 $100.

On October 31, 2006, we completed the sale of the disposal group for $19,310 in cash, with a potential additional payment subject to a final working capital settlement, and a $2,000 Canadian dollar denominated note (an equivalent of 1,715 U.S. dollars at December 31, 2006) which matures on October 31, 2009 and accrues interest at a specified Canadian bank prime rate plus 1.50% per annum. The carrying value of the related net assets was $21,705 on October 31, 2006. We recorded a loss of $603 associated with the sale of this disposal group, which represents the excess of the sales price over the carrying value of the assets less selling costs, the benefit of a transaction gain related to a release of cumulative translation adjustment associated with this business, and a charge of approximately $1,000 related to capital tax in Canada. We sold this disposal group to Paintearth Energy Services, Inc., an oilfield service company located in Calgary, Alberta, Canada, that employs two of our former employees as key managers. The sales agreement allowed Paintearth Energy Services, Inc. to use our subsidiary s trade name for a period of 120 days from November 1, 2006 through February 28, 2007. Proceeds from the sale of this disposal group were used to repay outstanding borrowings under the Canadian revolving portion of our credit facility.

Operating results for discontinued operations for the period January 1, 2006 through October 31, 2006, excluding the loss on the sale of the disposal group, and the year ended December 31, 2005 were as follows:

	Period January 1, 2006 through October 31, 2006	Year Ended December 31, 2005

Revenue	$	37,292	$	37,537
Income before taxes and minority interest	$	3,393	$	3,542
Net income before loss on disposal in 2006	$	2,406	$	2,941
Net income	$	1,803	$	2,941

17. Segment information:

SFAS No. 131, Disclosure About Segments of an Enterprise and Related Information, establishes standards for the reporting of information about operating segments, products and services, geographic areas, and major customers. The method of determining what information to report is based on the way our management organizes the operating segments for making operational decisions and assessing financial performance. We evaluate

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

performance and allocate resources based on net income (loss) from continuing operations before net interest expense, taxes, depreciation and amortization, minority interest and impairment loss (EBITDA). The calculation of EBITDA should not be viewed as a substitute for calculations under U.S. GAAP, in particular net income. EBITDA calculated by us may not be comparable to the EBITDA calculation of another company.

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, 2007, 2006 and 2005. Inter-segment transactions are accounted for on a cost recovery basis.

	C&PS	Drilling Services	Product Sales	Corporate	Total
Year Ended December 31, 2007					
Revenue from external customers	$ 1,262,100	$ 240,377	$ 152,760	$	$ 1,655,237
Inter-segment revenues	$ 1,148	$ 3,368	$ 61,320	$ (65,836)	$
EBITDA, as defined	$ 404,893	$ 69,628	$ 18,443	$ (28,136)	$ 464,828
Depreciation and amortization	$ 114,139	$ 17,023	$ 2,918	$ 1,881	$ 135,961
Operating income (loss)	$ 290,754	$ 52,605	$ 15,525	$ (30,017)	$ 328,867
Capital expenditures	$ 305,940	$ 60,259	$ 4,323	$ 2,032	$ 372,554
As of December 31, 2007					
Segment assets	$ 1,651,653	$ 287,563	$ 89,492	$ 26,051	$ 2,054,759
Year Ended December 31, 2006					
Revenue from external customers	$ 873,493	$ 215,255	$ 123,676	$	$ 1,212,424
Inter-segment revenues	$ 136	$ 4,179	$ 59,097	$ (63,412)	$
EBITDA, as defined	$ 257,630	$ 78,543	$ 18,708	$ (20,922)	$ 333,959
Depreciation and amortization	$ 65,317	$ 10,599	$ 1,943	$ 1,606	$ 79,465
Operating income (loss)	$ 192,313	$ 67,944	$ 16,765	$ (22,528)	$ 254,494
Capital expenditures	$ 234,380	$ 57,853	$ 9,349	$ 2,340	$ 303,922
As of December 31, 2006					
Segment assets	$ 1,369,906	$ 245,806	$ 96,537	$ 28,075	$ 1,740,324
Year Ended December 31, 2005					
Revenue from external customers	$ 510,304	$ 129,117	$ 80,768	$	$ 720,189
EBITDA, as defined	$ 114,033	$ 42,336	$ 12,634	$ (11,613)	$ 157,390
Depreciation and amortization	$ 40,149	$ 5,666	$ 1,250	$ 1,445	$ 48,510
Operating income (loss)	$ 73,884	$ 36,670	$ 11,384	$ (13,058)	$ 108,880
Capital expenditures	$ 81,086	$ 38,574	$ 4,382	$ 3,173	$ 127,215
As of December 31, 2005					
Segment assets	$ 706,135	$ 137,556	$ 74,344	$ 19,618	$ 937,653

Inter-segment sales were not significant for the year ended December 31, 2005. The increase in inter-segment sales in 2006 and 2007 was largely due to service work performed and drilling rigs assembled by a subsidiary in the product sales business segment that sold such services and rigs to a subsidiary in the drilling services business segment and certain subsidiaries in the completion and production services business segment, and due to the sale of drill pipe through our supply stores in the product segment to affiliates in other business segments.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

We do not allocate net interest expense, tax expense or minority interest to the operating segments. The write-off of deferred financing fees of $170 and $3,315 during the years ended December 31, 2006 and 2005, respectively, was recorded as a decrease in 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, 2007, 2006 and 2005.

	2007	2006	2005
Segment operating income	$ 328,867	$ 254,494	$ 108,880
Interest expense	62,673	40,759	24,460
Interest income	(1,636)	(1,387)	
Income taxes	93,741	77,888	33,115
Minority interest	(569)	(49)	384
Impairment loss	13,094		
Net income from continuing operations	$ 161,564	$ 137,283	$ 50,921

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, 2007:

	C&PS	Drilling Services	Product Sales	Total
Balance at December 31, 2004	$ 124,197	$ 15,022	$ 1,684	$ 140,903
Acquisitions	50,089		1,610	51,699
Purchase of minority interest	66,279	18,805	8,708	93,792
Accrue contingent consideration	5,800			5,800
Contingency adjustment and other	263			263
Foreign currency translation	1,164		30	1,194
Balance at December 31, 2005	247,792	33,827	12,032	293,651
Acquisitions	230,681	1,049		231,730
Stock issued in accordance with earn-out provisions of purchase agreements	27,359			27,359
Foreign currency translation	(69)			(69)
Balance at December 31, 2006	$ 505,763	$ 34,876	$ 12,032	$ 552,671
Acquisitions	19,391			19,391
Impairment charge(a)	(13,360)			(13,360)
Amount paid pursuant to earn-out agreement	800			800
Contingency adjustment and other(b)	(6,068)	(579)		(6,647)

Foreign currency translation	7,178		455	7,633
Balance at December 31, 2007	$ 513,704	$ 34,297	$ 12,487	$ 560,488

(a) In accordance with SFAS No. 142, Goodwill and Other Intangible Assets, we are required to test our goodwill for impairment annually, or more often if indicators of impairment exist. We performed this test and determined that goodwill associated with our Canadian reportable unit was deemed to be impaired as of the test date, resulting in an impairment charge of $13,360. See Note 2, Significant Accounting Policies Fair Value Measurements.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

(b) The contingency adjustment includes a reclassification of $3,485 from goodwill to identifiable intangible assets, primarily non-compete agreements and customer relationships, which were identified upon acquisition but for which the fair value was recently determined based upon estimates calculated by a third-party appraiser. Of this amount, $2,017 related to the acquisition of Pumpco Services, Inc. in November 2006. In addition, we recorded an adjustment to reduce goodwill related to the acquisition of Pumpco Services, Inc. totaling $3,136 associated with certain federal income tax liabilities recorded at the acquisition date that were deemed to be unnecessary based upon the 2006 federal tax return prepared in 2007. Partially offsetting these reductions to goodwill were additional charges associated with final working capital adjustments for several 2006 and 2007 acquisitions.

Geographic information (c):

	United States	Canada	Other International	Total
Year Ended December 31, 2007				
Revenue by sale origin to external customers	$ 1,496,284	$ 80,933	$ 78,020	$ 1,655,237
Income (loss) before taxes and minority interest	$ 260,132	$ (13,484)	$ 8,088	$ 254,736
December 31, 2007				
Long-lived assets	$ 1,518,318	$ 94,434	$ 13,683	$ 1,626,435
Year Ended December 31, 2006				
Revenue by sale origin to external customers	$ 1,067,708	$ 88,533	$ 56,183	$ 1,212,424
Income before taxes and minority interest	$ 198,434	$ 5,977	$ 10,711	$ 215,122
December 31, 2006				
Long-lived assets	$ 1,226,342	$ 117,809	$ 5,533	$ 1,349,684
Year Ended December 31, 2005				
Revenue by sale origin to external customers	$ 605,019	$ 73,644	$ 41,526	$ 720,189
Income before taxes and minority interest	$ 75,718	$ 2,859	$ 5,843	$ 84,420
December 31, 2005				
Long-lived assets	$ 597,834	$ 85,685	$ 6,648	$ 690,167

(c) 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.

We did not have revenues from any single customer which amounts to 10% or more of our total annual revenue for the years ended December 31, 2007, 2006 or 2005.

18. 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 the businesses.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

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 the 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.

At June 30, 2007, we had accrued $1,600 in additional insurance premium related to a cost-sharing provision of our general liability policy, of which we paid $1,444 in August 2007. Although we do not believe it is probable that we will incur additional costs pursuant to this provision, 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.

19. Financial instruments:

(a) Interest rate risk:

We manage our exposure to interest rate risks through a combination of fixed and floating rate borrowings. At December 31, 2007, 21% of our long-term debt was floating rate borrowings. Of the remaining debt, 99% relates to the senior notes issued in December 2006 with a fixed interest rate of 8%.

(b) Foreign currency rate risk:

We are exposed to foreign currency fluctuations in relation to our foreign operations. Approximately 5% and 7% of our revenues from continuing operations were derived from operations conducted in Canadian dollars for the years ended December 31, 2007 and 2006, respectively. For the year ended December 31, 2007, we recorded a net loss from continuing operations before taxes and minority interest of $13,484 related to our Canadian operations. Total assets denominated in Canadian dollars at December 31, 2007 and 2006 were $120,378 and $118,671, 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.

20. Commitments and contingences:

We have non-cancelable operating lease commitments for equipment and office space. These commitments for the next five years were as follows at December 31, 2007:

2008	$ 20,222
2009	13,291
2010	7,920
2011	4,768

2012	3,357
Thereafter	4,382
	$ 53,940

We expensed operating lease payments totaling $23,404, $20,258 and $10,110 for the years ended December 31, 2007, 2006 and 2005, respectively.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

21. 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 $2,999, $2,306 and $2,976 for the years ended December 31, 2007, 2006 and 2005, respectively.

In connection with CES acquisition of Hamm Co. in 2004, CES entered into that 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 2007 which totaled $52,027, of which $51,340 was sold to CRI, and $687 was sold to other companies. In 2006, these sales totaled $37,405, of which $37,008 was sold to CRI, and $397 was sold to other companies. Sales to CRI for the year ended December 31, 2005 totaled $21,255. We also purchased services from companies that are majority-owned by certain of our directors which totaled $1,260 in 2007, of which $1,211 was purchased from CRI and $49 was purchased from other companies. These purchases for 2006 totaled $755, of which $614 was purchased from CRI and $141 was purchased from other companies. Purchases from CRI for the year ended December 31, 2005 totaled $2,164. At December 31, 2007 and 2006, our trade receivables included amounts from CRI of $7,611 and $9,327, respectively, and our trade payables included amounts due to CRI of $47 and $197, respectively.

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, 2007 and 2006. In 2007, these sales totaled $22,391, of which $4,356 was sold to HEP Oil (HEP), $11,578 was sold to Cimarron, $4,487 was sold to Peak Oilfield and $1,970 was sold to other companies. In 2006, these sales totaled $21,044, of which $8,324 was sold to HEP, $12,698 was sold to Cimarron and $22 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. In 2005, we provided services totaling $8,794 to these companies, of which $7,804 was sold to HEP and $990 was sold to other companies. We also purchased services from companies majority-owned by certain officers, or current or former officers of our subsidiaries. For 2007, these purchases totaled $70,598, of which $64,503 was purchased from Ortowski Construction for the manufacture of pressure pumping fleets, $70 was purchased from HEP and $6,025 was purchased from other companies. Ortowski Construction is owned by a former officer of one of our subsidiaries. In 2006, we purchased $5,598, of which $216 was purchased from HEP and $5,382 was purchased from other companies. Purchases from these companies in 2005 totaled $5,149, of which $598 related to HEP, $1,390 related to other companies owned by the same officer, $2,805 related to companies owned by an officer of Parchman and $356 related to other companies. At December 31, 2007 and 2006, our trade receivables included amounts from HEP of $666 and $2,483, respectively, and amounts due from Cimarron of $519 and $859, respectively. Our trade payables and accrued expenses at December 31, 2007 included amounts payable to Ortowski construction of $6,105. There were no amounts payable to HEP or Cimarron at December 31, 2007 and 2006.

We provided services totaling $2,068, $5,367 and $1,910 for the years ended December 31, 2007, 2006 and 2005, 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, 2007 and 2006, our trade receivables included amounts due from Laramie totaling $27 and $668, respectively.

During 2007 and 2006, we provided services totaling $11,154 and $3,659, respectively, and purchased services totaling $15,759 and $28,114, respectively, from companies, or their affiliates, that formerly employed our current officers or for customers on whose board of directors certain of our current directors serve.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Effective November 7, 2003, we entered into a financial advisory services agreement with an affiliate of our major shareholder, which provided for an upfront fee of $250 and quarterly payments of $31. This agreement was cancelled effective September 12, 2005. Effective August 14, 2004, we entered into a financial advisory services agreement with an affiliate of our major shareholder pursuant to which we paid fees of $1,600 in conjunction with our 2004 acquisitions, and management fees of $350 during 2004. This agreement was cancelled effective September 12, 2005.

We entered into subordinated note agreements with certain employees, including current officers of subsidiaries, whereby we are obligated to pay an aggregate principal amount of $8,450 pursuant to promissory notes issued in conjunction with 2005 and 2004 business acquisitions. Of this amount, $5,000 was repaid in May 2006. The remaining notes mature in 2009. See Note 12, Long-term Debt.

On December 1, 2001, Bison Oilfield Tools, Ltd. (Bison), and PEG, a subsidiary of IPS, entered into a lease agreement pursuant to which PEG leases real property from Bison. A former director of IPS controls Bison as the president of its two general partners. IPS paid Bison $4 per month through December 2006.

Premier Integrated Technologies Ltd. (PIT), an affiliate of IPS, purchased $2,290, $2,083 and $819 of machining services from a company controlled by employees of PIT during the years ended December 31, 2007, 2006 and 2005, respectively.

On September 29, 2005, we entered into an Asset Purchase Agreement with Spindletop and Mr. Schmitz, a former officer of one of our subsidiaries. Pursuant to the agreement, we purchased the assets of Spindletop in exchange for approximately $200 cash and 90,364 shares of our common stock. Mr. Schmitz was a member of our key operational management who resigned as an officer of one of our subsidiaries in late 2006. Mr. Schmitz remained in our employ as of December 31, 2006. On January 1, 2007, Mr. Schmitz purchased the assets of one of our subsidiaries for $412, resulting in a gain on the sale of $156.

On November 8, 2006, we acquired Pumpco, a provider of pressure pumping services in the Barnett Shale play of north Texas, in exchange for consideration of $144,635 in cash, net of cash acquired, the issuance of 1,010,566 shares of our common stock and the assumption of $30,250 of debt held by Pumpco at the time of the acquisition. Pumpco was purchased from the stockholders of Pumpco. Prior to the acquisition, SCF-VI, L.P. (SCF-VI) was the majority stockholder of Pumpco. SCF-VI is an affiliate of SCF-IV, L.P. (SCF-IV), which held approximately 35% of our outstanding common stock at the time of the acquisition. Andy Waite and David Baldwin were our Directors at the time of the acquisition and serve as officers of the ultimate general partner of SCF-VI. Our Board of Directors established a Special Committee of directors, each independent of SCF-IV or any of its affiliates, to review and approve the terms of the transaction. UBS Investment Bank acted as exclusive financial advisor to the Special Committee. In addition, John Schmitz, one of our key members of management during 2006, was a stockholder of Pumpco prior to the acquisition. The nature and amount of the consideration paid was determined by negotiations between the stockholders of Pumpco and our management and the Special Committee of our Board of Directors.

22. Retirement plans:

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 maximums range from 20% to 60%, depending on the plan. We make matching contributions at 25%   50% of the first 6% or 7% of the employee s contributions, depending on the plan. The employer contributions vest immediately with respect to the Canadian RRSP plan and vest at varying rates under the U.S. 401(k) plans. Vesting ranges from immediately to a graduated scale with 100% vesting after five years of service.

We expensed $5,216, $3,194 and $2,039 related to our various defined contribution plans for the years ended December 31, 2007, 2006 and 2005, respectively.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

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 $814 and $275 at December 31, 2007 and 2006, respectively, related to our liability under this benefit arrangement in Mexico.

23. Unaudited selected quarterly data:

The following table presents selected quarterly financial data for the years ended December 31, 2007 and 2006 (unaudited, in thousands, except per share amounts):

	2007 Quarter Ended			
	March 31,	**June 30,**	**September 30,**	**December 31,**
Revenues	$ 407,067	$ 410,715	$ 412,923	$ 424,532
Operating income	$ 92,203	$ 83,861	$ 76,697	$ 63,012
Net income	$ 47,350	$ 43,783	$ 41,608	$ 28,823
Earnings per share:				
Basic	$ 0.66	$ 0.61	$ 0.58	$ 0.40
Diluted	$ 0.65	$ 0.60	$ 0.57	$ 0.39

	2006 Quarter Ended			
	March 31,	**June 30,**	**September 30,**	**December 31,**
Revenues	$ 262,346	$ 264,536	$ 322,034	$ 363,508
Operating income	$ 54,906	$ 50,513	$ 72,234	$ 77,011
Net income from continuing operations	$ 26,915	$ 26,601	$ 39,669	$ 44,098
Net income	$ 28,113	$ 27,154	$ 40,239	$ 43,580
Earnings per share continuing operations(a):				
Basic	$ 0.48	$ 0.40	$ 0.57	$ 0.62
Diluted	$ 0.46	$ 0.39	$ 0.55	$ 0.61
Earnings per share:				
Basic	$ 0.51	$ 0.40	$ 0.58	$ 0.62
Diluted	$ 0.48	$ 0.39	$ 0.56	$ 0.60

(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.

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

24. 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, 2007 and 2006; (2) condensed consolidating statements of operations for the years ended December 31, 2007, 2006 and 2005; and (3) condensed consolidating statements of cash flows for the years ended December 31, 2007, 2006 and 2005.

Prior to January 1, 2006, the operating activities of our parent company were not separated from the activities of the guarantor subsidiaries. Effective January 1, 2006, Complete Production Services, Inc., our parent company, contributed its operating assets to a new wholly-owned subsidiary, and began to operate as a holding company. Therefore, we have presented the assets of our parent and the guarantor subsidiaries as a combined entity for purposes of the preparation of these condensed consolidating financial statements for each period presented prior to January 1, 2006.

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Balance Sheet
December 31, 2007

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Current assets					
Cash and cash equivalents	$ 8,217	$ 5,606	$ 6,605	$ (6747)	$ 13,681
Trade accounts receivable, net	62	299,709	28,914		328,685
Inventory, net		43,213	13,855		57,068
Prepaid expenses and other current assets	7,113	20,881	896		28,890
Total current assets	15,392	369,409	50,270	(6,747)	428,324
Property, plant and equipment, net	4,623	974,674	55,398		1,034,695
Investment in consolidated subsidiaries	850,238	114,529		(964,767)	
Inter-company receivable	883,247	371		(883,618)	
Goodwill	93,792	418,284	48,412		560,488
Other long-term assets, net	14,804	12,509	3,939		31,252
Total assets	$ 1,862,096	$ 1,889,776	$ 158,019	$ (1,855,132)	$ 2,054,759
Current liabilities Current maturities of long-term debt	$	$ 605	$ 70	$	$ 675
Accounts payable	1,364	61,419	8,631	(6,747)	64,667
Accrued liabilities	10,254	40,071	7,516		57,841
Accrued payroll and payroll burdens	1,278	22,007	1,217		24,502
Notes payable	15,319	35			15,354
Taxes payable			6,506		6,506
Total current liabilities	28,215	124,137	23,940	(6,747)	169,545
Long-term debt	810,000	3,692	12,295		825,987
Inter-company payable		883,247	371	(883,618)	
Deferred income taxes	93,557	28,462	6,885		128,904
Minority interest					
Total liabilities	931,772	1,039,538	43,491	(890,365)	1,124,436
Stockholders equity Total stockholders equity	930,324	850,238	114,528	(964,767)	930,323

Total liabilities and stockholders equity	$	1,862,096	$	1,889,776	$	158,019	$	(1,855,132)	$	2,054,759

COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Condensed Consolidating Balance Sheet
December 31, 2006

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Current assets					
Cash and cash equivalents	$ 6,517	$ 9,533	$ 7,312	$ (3,488)	$ 19,874
Trade accounts receivable, net	32	273,990	27,742		301,764
Inventory, net		33,899	10,031		43,930
Prepaid expenses and other current assets	1,495	21,307	2,270		25,072
Total current assets	8,044	338,729	47,355	(3,488)	390,640
Property, plant and equipment, net	3,384	713,952	54,367		771,703
Investment in consolidated subsidiaries	398,414	91,740		(490,154)	
Inter-company receivable	1,007,052			(1,007,052)	
Goodwill	93,792	416,515	42,364		552,671
Other long-term assets, net	16,473	5,725	3,112		25,310
Total assets	$ 1,527,159	$ 1,566,661	$ 147,198	$ (1,500,694)	$ 1,740,324
Current liabilities Current maturities of long-term debt	$	$ 923	$ 141	$	$ 1,064
Accounts payable	1,545	64,958	8,355	(3,488)	71,370
Accrued liabilities	4,925	27,664	6,474		39,063
Accrued payroll and payroll burdens	2,436	18,682	1,184		22,302
Notes payable	17,087				17,087
Taxes payable	8,065		2,454		10,519
Total current liabilities	34,058	112,227	18,608	(3,488)	161,405
Long-term debt	728,668	4,093	17,816		750,577
Inter-company payable		1,000,870	6,182	(1,007,052)	
Deferred income taxes	29,212	51,057	10,536		90,805
Minority interest			2,316		2,316
Total liabilities	791,938	1,168,247	55,458	(1,010,540)	1,005,103
Stockholders equity Total stockholders equity	735,221	398,414	91,740	(490,154)	735,221
	$ 1,527,159	$ 1,566,661	$ 147,198	$ (1,500,694)	$ 1,740,324

Total liabilities and stockholders
equity

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Condensed Consolidated Statement of Operations
Year Ended December 31, 2007

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Revenue:					
Service	$	$ 1,386,419	$ 120,368	$ (4,310)	$ 1,502,477
Product		114,175	38,585		152,760
		1,500,594	158,953	(4,310)	1,655,237
Service expenses		776,097	91,918	(4,310)	863,705
Product expenses		91,169	25,388		116,557
Selling, general and administrative expenses	28,136	168,595	13,416		210,147
Depreciation and amortization	1,102	124,517	10,342		135,961
Income from continuing operations before interest, taxes and minority interest	(29,238)	340,216	17,889		328,867
Interest expense	63,643	22,604	1,101	(24,675)	62,673
Interest income	(24,804)	(1,222)	(285)	24,675	(1,636)
Impairment loss			13,094		13,094
Equity in earnings of consolidated affiliates	(195,659)	(474)		196,133	
Income from continuing operations before taxes and minority interest	127,582	319,308	3,979	(196,133)	254,736
Taxes	(33,982)	123,649	4,074		93,741
Income from continuing operations before minority interest	161,564	195,659	(95)	(196,133)	160,995
Minority interest			(569)		(569)
Net income	$ 161,564	$ 195,659	$ 474	$ (196,133)	$ 161,564

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Condensed Consolidated Statement of Operations
Year Ended December 31, 2006

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Revenue:					
Service	$	$ 975,523	$ 117,137	$ (3,912)	$ 1,088,748
Product		94,882	28,794		123,676
		1,070,405	145,931	(3,912)	1,212,424
Service expenses		539,010	87,688	(3,912)	622,786
Product expenses		71,751	16,424		88,175
Selling, general and administrative expenses	20,752	133,765	12,817		167,334
Depreciation and amortization	1,192	68,332	9,941		79,465
Income from continuing operations before interest, taxes and minority interest	(21,944)	257,547	19,061		254,664
Interest expense	40,238	18,086	1,920	(19,485)	40,759
Interest income	(20,733)		(139)	19,485	(1,387)
Write-off of deferred financing costs		170			170
Equity in earnings of consolidated affiliates	(162,045)	(13,786)		175,831	
Income from continuing operations before taxes and minority interest	120,596	253,077	17,280	(175,831)	215,122
Taxes	(18,490)	91,032	5,346		77,888
Income from continuing operations before minority interest	139,086	162,045	11,934	(175,831)	137,234
Minority interest			(49)		(49)
Net income from continuing operations	139,086	162,045	11,983	(175,831)	137,283
Discontinued operations (net of tax)			1,803		1,803
Net income	$ 139,086	$ 162,045	$ 13,786	$ (175,831)	$ 139,086

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Condensed Consolidated Statement of Operations
Year Ended December 31, 2005

	Parent and Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Revenue:				
Service	$ 554,639	$ 91,374	$ (6,592)	$ 639,421
Product	61,536	19,232		80,768
	616,175	110,606	(6,592)	720,189
Service expenses	332,805	67,643	(6,592)	393,856
Product expenses	44,651	12,211		56,862
Selling, general and administrative expenses	97,552	11,214		108,766
Depreciation and amortization	40,308	8,202		48,510
Income from continuing operations before interest, taxes and minority interest	100,859	11,336		112,195
Interest expense	33,074	2,507	(11,121)	24,460
Interest income	(11,121)		11,121	
Write-off of deferred financing costs	3,315			3,315
Equity in earnings of consolidated affiliates	(8,971)		8,971	
Income from continuing operations before taxes and minority interest	84,562	8,829	(8,971)	84,420
Taxes	30,700	2,415		33,115
Income from continuing operations before minority interest	53,862	6,414	(8,971)	51,305
Minority interest		384		384
Net income from continuing operations	53,862	6,030	(8,971)	50,921
Discontinued operations (net of tax)		2,941		2,941
Net income	$ 53,862	$ 8,971	$ (8,971)	$ 53,862

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2007

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Cash provided by:					
Net income	$ 161,564	$ 195,659	$ 474	$ (196,133)	$ 161,564
Items not affecting cash:					
Equity in earnings of consolidated affiliates	(195,659)	(474)		196,133	
Depreciation and amortization	1,102	124,517	10,342		135,961
Other	1,603	49,725	10,869		62,197
Changes in operating assets and liabilities, net of effect of acquisitions	78,278	(102,401)	6,220	(3,259)	(21,162)
Net cash provided by operating activities	46,888	267,026	27,905	(3,259)	338,560
Investing activities:					
Business acquisitions, net of cash acquired		(50,406)			(50,406)
Additions to property, plant and equipment	(2,029)	(349,568)	(16,062)		(367,659)
Inter-company advances	(116,113)			116,113	
Other		8,325	945		9,270
Net cash provided by (used for) investing activities	(118,142)	(391,649)	(15,117)	116,113	(408,795)
Financing activities:					
Issuances of long-term debt	333,684		10,106		343,790
Repayments of long-term debt	(252,352)	(1,230)	(15,187)		(268,769)
Repayments of notes payable	(18,846)				(18,846)
Inter-company borrowings (repayments)		121,926	(5,813)	(116,113)	
Proceeds from issuances of common stock	4,179				4,179
Other	6,289				6,289
Net cash provided by (used in) financing Activities	72,954	120,696	(10,894)	(116,113)	66,643
Effect of exchange rate changes on cash			(2,601)		(2,601)

Change in cash and cash equivalents		1,700		(3,927)		(707)		(3,259)		(6,193)
Cash and cash equivalents, beginning of period		6,517		9,533		7,312		(3,488)		19,874
Cash and cash equivalents, end of period	$	8,217	$	5,606	$	6,605	$	(6,747)	$	13,681

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2006

	Parent	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Cash provided by:					
Net income	$ 139,086	$ 162,045	$ 13,786	$ (175,831)	$ 139,086
Items not affecting cash:					
Equity in earnings of consolidated affiliates	(162,045)	(13,786)		175,831	
Depreciation and amortization	1,192	68,332	10,289		79,813
Other	8,946	29,502	(641)		37,807
Changes in operating assets and liabilities, net of effect of acquisitions	37,966	(105,435)	1,994	(3,488)	(68,963)
Net cash provided by operating activities	25,145	140,658	25,428	(3,488)	187,743
Investing activities:					
Business acquisitions, net of cash acquired		(360,730)	(8,876)		(369,606)
Additions to property, plant and equipment	(810)	(289,680)	(13,432)		(303,922)
Inter-company advances	(504,609)			504,609	
Purchase of short-term securities	(165,000)				(165,000)
Proceeds from sale of short-term securities	165,000				165,000
Proceeds from sale of disposal group			19,310		19,310
Other	(808)	4,168	(5)		3,355
Net cash used for investing activities	(506,227)	(646,242)	(3,003)	504,609	(650,863)
Financing activities:					
Issuances of long-term debt	598,133		10,570		608,703
Repayments of long-term debt	(1,028,631)		(25,158)		(1,053,789)
Repayments of notes payable	(13,589)				(13,589)
Inter-company borrowings (repayments)		509,074	(4,465)	(504,609)	
Borrowings under senior notes	650,000				650,000
Proceeds from issuances of common stock	291,674				291,674

Other	(11,623)				(11,623)
Net cash provided by (used in) financing activities	485,964	509,074	(19,053)	(504,609)	471,376
Effect of exchange rate changes on cash			213		213
Change in cash and cash equivalents	4,882	3,490	3,585	(3,488)	8,469
Cash and cash equivalents, beginning of period	1,635	6,043	3,727		11,405
Cash and cash equivalents, end of period	$ 6,517	$ 9,533	$ 7,312	$ (3,488)	$ 19,874

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2005

	Parent and Guarantor Subsidiaries	Non-guarantor Subsidiaries	Eliminations/ Reclassifications	Consolidated
Cash provided by:				
Net income	$ 53,862	$ 8,971	$ (8,971)	$ 53,862
Items not affecting cash:				
Equity in earnings of consolidated affiliates	(8,971)		8,971	
Depreciation and amortization	40,308	8,532		48,840
Other	22,146	3,981		26,127
Changes in operating assets and liabilities, net of effect of acquisitions	(49,966)	(2,436)		(52,402)
Net cash provided by operating activities	57,379	19,048		76,427
Investing activities:				
Business acquisitions, net of cash acquired	(57,956)	(9,733)		(67,689)
Additions to property, plant and equipment	(115,992)	(9,150)		(125,142)
Inter-company advances	(11,450)		11,450	
Other	3,521	952		4,473
Net cash provided by (used for) investing activities	(181,877)	(17,931)	11,450	(188,358)
Financing activities:				
Issuances of long-term debt	673,336	68,263		741,599
Repayments of long-term debt	(400,842)	(63,763)		(464,605)
Net repayments under lines of credit	(2,639)	(16,964)		(19,603)
Repayments of notes payable	(1,690)			(1,690)
Inter-company borrowings (repayments)		11,450	(11,450)	
Proceeds from issuances of common stock	12,267			12,267
Dividends paid	(146,894)			(146,894)
Other	(4,408)	(4,527)		(8,935)
Net cash provided by (used in) financing activities	129,130	(5,541)	(11,450)	112,139
Effect of exchange rate changes on cash		(350)		(350)
Change in cash and cash equivalents	4,632	(4,774)		(142)
Cash and cash equivalents, beginning of period	3,046	8,501		11,547

Cash and cash equivalents, end of period	$	7,678	$	3,727	$		$	11,405

25. Recent accounting pronouncements and authoritative literature:

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115. This pronouncement permits entities to use the fair value method to measure certain financial assets and liabilities by electing an irrevocable option to use the fair value method at specified election dates. After election of the option, subsequent changes in fair value would result in the recognition of unrealized gains or losses as period costs during the period the change occurred. SFAS No. 159 becomes effective as of the beginning of the first fiscal year that begins after November 15, 2007,

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

with early adoption permitted. However, entities may not retroactively apply the provisions of SFAS No. 159 to fiscal years preceding the date of adoption.

In February 2008, the FASB issued FASB Staff Position No. 157-2 which postpones certain provisions of SFAS No. 157 related to disclosure requirements for non-financial assets and liabilities except for items which are recognized and disclosed at fair value in the financial statements on a recurring basis. We adopted SFAS No. 157 on January 1, 2007. For additional disclosure related to SFAS No. 157, see Note 2, Significant Accounting Policies Fair Value Measurements.

In December 2007, the FASB issued SFAS No. 160, Non-controlling Interests in Consolidating Financial Statements an Amendment of ARB No. 51. This pronouncement establishes accounting and reporting standards for non-controlling interests, commonly referred to as minority interests. Specifically, this statement requires that the non-controlling interest be presented as a component of equity on the balance sheet, and that net income be presented prior to adjustment for the non-controlling interests portion of earnings with the portion of net income attributable to the parent company and the non-controlling interest both presented on the face of the statement of operations. In addition, this pronouncement provides a single method of accounting for changes in the parent s ownership interest in the non-controlling entity, and requires the parent to recognize a gain or loss in net income when a subsidiary with a non-controlling interest is deconsolidated. Additional disclosure items are required related to the non-controlling interest. This pronouncement becomes effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The statement should be applied prospectively as of the beginning of the fiscal year that the statement is adopted. However, the disclosure requirements must be applied retrospectively for all periods presented. We are currently evaluating the impact that SFAS No. 160 may have on our financial position, results of operations and cash flows.

In December 2007, the FASB revised SFAS No. 141, Business Combinations which will replace that pronouncement in its entirety. While the revised statement will retain the fundamental requirements of SFAS No. 141, it will also require 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, the statement provides guidance for recognizing pre-acquisition contingencies and states that an acquirer must recognize assets and liabilities assumed arising from contractual contingencies as of the acquisition date, measured at acquisition-date fair values, but 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 FASB Concepts Statement No. 6, Elements of Financial Statements. Furthermore, this statement 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 it requires that the acquirer recognize that excess in earnings as a gain attributable to the acquirer. This statement becomes effective at the beginning of the first annual reporting period beginning on or after December 15, 2008, and must be applied prospectively. We are currently evaluating the impact that this statement may have on our financial position, results of operations and cash flows.

25. Subsequent events:

(a) 2008 Stock Option and Restricted Stock Grants:

On January 31, 2008, 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 287,500 shares of non-vested restricted stock at a grant price of $15.90 We expect to recognize compensation expense associated with this grant of non-vested restricted stock totaling $4,571 ratably over the three-year vesting period. In addition, we granted 345,000 stock options to purchase shares of our common stock at an exercise price of $15.90. These stock options vest ratably over a three-year period. We will recognize

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COMPLETE PRODUCTION SERVICES, INC.

Notes to Consolidated Financial Statements (Continued)

compensation expense associated with these stock option grants over the vesting period in accordance with SFAS No. 123R. Further, we plan to seek shareholder approval to increase the shares available for grant through our stock compensation plans, pursuant to which, we expect to issue additional non-vested restricted stock to our senior management and directors in May 2008.

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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, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation 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. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2007, to ensure that information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2007, 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 has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a 15(f) and 15d 15(f) under the Securities and Exchange Act of 1934). 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 the our assets that could have a material effect on our consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies 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, 2007. 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, as of December 31, 2007, our internal control over financial reporting was effective.

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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 29, 2008, also included in this Annual Report.

/s/ Joseph C. Winkler
Joseph C. Winkler
Chairman and Chief Executive Officer
February 29, 2008

/s/ J. Michael Mayer
J. Michael Mayer
Senior Vice President and Chief Financial Officer
February 29, 2008

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

None.

PART III

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

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2007.

Item 11. ***Executive Compensation.***

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2007.

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

Item 12 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2007.

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

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2007.

Item 14. ***Principal Accounting Fees and Services.***

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Securities Exchange Act of 1934. The Registrant expects to file a definitive proxy statement with the Securities and Exchange Commission within 120 days after the close of the year ended December 31, 2007.

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PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

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

(b) *Exhibits*

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

Exhibit No.	Exhibit Title	Incorporated by Rleference to the Following
2.1	Stock Purchase Agreement dated November 11, 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
3.1	Amended and Restated Certificate of Incorporation	Form S-1/A, filed January 17, 2006, (file no. 333-128750)
3.2	Amended and Restated Bylaws, dated February 21, 2008	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	Form 8-K, filed December 8, 2006

	8% Senior Notes due 2016	
4.3	Registration Rights Agreement dated November 8, 2006 pursuant to Stock Purchase Agreement dated November 11, 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)

Exhibit No.	Exhibit Title	Incorporated by Rleference to the Following
10.2*	Employment Agreement dated as of June 22, 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 17, 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 2001 Stock Incentive Plan	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
10.11*		

	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)
10.12*	I.E. Miller Services, Inc. 2004 Stock Incentive Plan	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.13	Strategic Customer Relationship Agreement	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.14*	Form of Restricted Stock Grant Agreement (Employee)	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.15*	Form of Restricted Stock Grant Agreement (Non-employee Director)	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.16*	Form of Non-Qualified Option Grant Agreement (Executive Officer)	Form S-1/A, filed April 4, 2006, (file no. 333-128750)

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Exhibit No.	Exhibit Title	Incorporated by Rleference to the Following
10.17*	Form of Non-Qualified Option Grant Agreement (Non-Employee Director)	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
10.18*	Compensation Package Term Sheet J. Michael Mayer	Form S-1/A, filed March 17, 2006, (file no. 333-128750)
10.19*	Compensation Package Term Sheet James F. Maroney, III	Form S-1/A, filed March 17, 2006, (file no. 333-128750)
10.20*	Compensation Package Term Sheet Kenneth L. Nibling	Form S-1/A, filed March 17, 2006, (file no. 333-128750)
10.21*	Incentive Plan Guidelines for Senior Management	Form 8-K, filed February 21, 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)

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Exhibit No.	Exhibit Title	Incorporated by Rleference to the Following
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)
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

* Management employment agreements, compensatory arrangements or option plans

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 J. Michael Mayer, 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 resubstitution, 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 29, 2008
/s/ J. MICHAEL MAYER J. Michael Mayer	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 29, 2008
/s/ ROBERT L. WEISGARBER Robert L. Weisgarber	Vice President-Accounting and Controller (Principal Accounting Officer)	February 29, 2008
/s/ ANDREW L. WAITE Andrew L. Waite	Director	February 29, 2008
/s/ ROBERT BOSWELL Robert Boswell	Director	February 29, 2008

/s/ HAROLD G. HAMM	Director	February 29, 2008
Harold G. Hamm		
/s/ MIKE MCSHANE	Director	February 29, 2008
Mike McShane		
/s/ W. MATT RALLS	Director	February 29, 2008
W. Matt Ralls		
/s/ MARCUS WATTS	Director	February 29, 2008
Marcus Watts		
/s/ R. GRAHAM WHALING	Director	February 29, 2008
R. Graham Whaling		
/s/ JAMES D. WOODS	Director	February 29, 2008
James D. Woods		

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EXHIBIT INDEX

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
2.1	Stock Purchase Agreement dated November 11, 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
3.1	Amended and Restated Certificate of Incorporation	Form S-1/A, filed January 17, 2006, (file no. 333-128750)
3.2	Amended and Restated Bylaws, dated February 21, 2008	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 11, 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 22, 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 17, 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)

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
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 2001 Stock Incentive Plan	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
10.11*	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)
10.12*	I.E. Miller Services, Inc. 2004 Stock Incentive Plan	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.13	Strategic Customer Relationship Agreement	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.14*	Form of Restricted Stock Grant Agreement (Employee)	Form S-1/A, filed November 15, 2005, (file no. 333-128750)

10.15*	Form of Restricted Stock Grant Agreement (Non-employee Director)	Form S-1/A, filed November 15, 2005, (file no. 333-128750)
10.16*	Form of Non-Qualified Option Grant Agreement (Executive Officer)	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
10.17*	Form of Non-Qualified Option Grant Agreement (Non-Employee Director)	Form S-1/A, filed April 4, 2006, (file no. 333-128750)
10.18*	Compensation Package Term Sheet J. Michael Mayer	Form S-1/A, filed March 17, 2006, (file no. 333-128750)
10.19*	Compensation Package Term Sheet James F. Maroney, III	Form S-1/A, filed March 17, 2006, (file no. 333-128750)
10.20*	Compensation Package Term Sheet Kenneth L. Nibling	Form S-1/A, filed March 17, 2006, (file no. 333-128750)
10.21*	Incentive Plan Guidelines for Senior Management	Form 8-K, filed February 21, 2007

Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
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	Form 10-Q, filed August 3, 2007, (file no. 001-32858)

	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.	
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)
21.1	Subsidiaries of Complete Production Services, Inc.	Filed herewith

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Exhibit No.	Exhibit Title	Incorporated by Reference to the Following
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

* Management employment agreements, compensatory arrangements or option plans