PATTERSON-UTI ENERGY, INC. | 2009 ANNUAL REPORT

COMPANY PROFILE Patterson-UTI Energy, Inc. subsidiaries provide onshore contract drilling and pressure pumping services to exploration and production companies in North America. Patterson-UTI Drilling Company LLC has approximately 350 marketable land-based drilling rigs that operate primarily in the oil and natural gas producing regions of Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada. Universal Well Services, Inc. provides pressure pumping services primarily in the Appalachian Basin.

Financial Highlights

(dollars in thousands, except per share amounts – unaudited)

	Year Ended December 31,				
	2005	**2006**	**2007**	**2008**	**2009**
Revenues	$1,618,444	$2,354,228	$1,986,096	$2,063,880	$ 781,946
Operating income (loss)	569,684	1,010,319	663,310	545,933	(48,214)
Net income (loss)	372,740	673,254	438,639	347,069	(38,290)
Net income (loss) per share –					
Basic	2.18	4.05	2.81	2.25	(0.25)
Diluted	2.15	4.00	2.78	2.23	(0.25)
Cash dividends per share	0.16	0.28	0.44	0.60	0.20
Total assets	1,795,781	2,192,503	2,465,199	2,712,817	2,662,152
Borrowings under revolving credit facility	—	120,000	50,000	—	—
Stockholders' equity	1,367,011	1,562,466	1,896,030	2,126,942	2,081,700
Working capital	382,448	335,052	227,577	338,761	263,960

Operational Highlights

(dollars in thousands – unaudited)

Contract Drilling:					
Operating days	100,591	108,192	89,095	93,068	33,394
Average revenue per day	$ 14.77	$ 20.05	$ 19.55	$ 19.38	$ 17.95
Average direct operating costs per day	$ 7.72	$ 9.26	$ 10.81	$ 11.16	$ 10.71
Average margin per day (1)	$ 7.05	$ 10.79	$ 8.74	$ 8.22	$ 7.24
Average rigs operating during the year	276	296	244	254	91
Number of rigs operated during the year	307	331	338	315	243
Number of wells drilled during the year	4,594	5,050	4,237	4,218	1,539
Pressure Pumping:					
Number of jobs	9,615	11,650	14,094	12,900	7,265
Average revenue per job	$ 9.69	$ 12.50	$ 14.39	$ 16.86	$ 22.22
Average direct operating costs per job	$ 5.72	$ 6.67	$ 7.47	$ 10.28	$ 15.34
Average margin per job (1)	$ 3.97	$ 5.83	$ 6.92	$ 6.58	$ 6.88
Hydraulic horsepower at end of year –					
Fluid	42,000	43,200	67,200	90,450	127,800
Nitrogen	19,200	22,200	28,200	32,400	35,400
Total	61,200	65,400	95,400	122,850	163,200

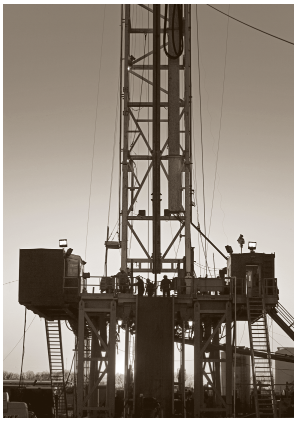
(1) Average margin represents average revenue minus average direct operating costs and excludes provisions for bad debts, other charges, depreciation, amortization and impairment and selling, general and administrative expenses.

PATTERSON-UTI ENERGY INC.

CONTRACT DRILLING

We have made significant upgrades over the last several years to our drilling fleet to match the needs of our customers. While conventional wells remain an important source of natural gas and oil, our customers have expanded the development of shale and other unconventional wells to help supply the long-term increasing demand for natural gas and oil in North America.

To address our customers' needs for drilling wells in the newer horizontal shale and other unconventional "resource plays", we have expanded our areas of operations and improved the capability of our drilling fleet.



We have continued to deliver new APEX™ rigs to the market and make performance and safety improvements to existing high capacity rigs. In 2009, we added 20 new APEX™ rigs to our fleet consisting of five APEX™ 1500, six APEX™ 1000 and nine APEX™ Walking rigs. And, we will deliver more of these rigs in 2010.

APEX™ 1500s are 1,500HP electric rigs with advanced EDS systems, 500 ton top drives, iron roughnecks, hydraulic catwalks, and other highly automated pipe handling equipment. APEX™ 1000s are 1,000HP electric rigs with advanced technology equipment similar to the APEX™ 1500s, but with a more compact design to fit on smaller locations, such as for drilling Marcellus Shale wells in Appalachia. APEX™ Walking rigs are designed to efficiently drill multiple wells from a single pad, by "walking" between the wellbores without requiring time to lower the mast and remove the drill pipe.

Additionally, to meet the needs of the increased demand for drilling horizontal wells, we have continued to acquire top drives and improve the capability of many of our non-APEX™ rigs to efficiently drill these wells. We are an active participant in the significant unconventional "resource plays" in the United States.

We remain a market leader in the drilling of conventional wells of varying depths. Over the last several years we have made substantial improvements to our overall drilling fleet to improve the drilling efficiency of these wells. Improvements have included higher capacity pumps, high-efficiency mud systems and iron roughnecks.

As of the end of 2009, we had 341 marketable land drilling rigs of which approximately 80% have depth capacities ranging from 12,000 to 30,000 feet.

PRESSURE PUMPING

Our pressure pumping business, Universal Well Services, Inc., continues to build on its 30 year tradition of offering a full line of pressure pumping services to our customers throughout the Appalachian Basin. In 2010, Universal is well positioned, both in locality and capability, to capitalize on the shale gas market in Appalachia. Locations in Pennsylvania, West Virginia, Kentucky and Tennessee provide services in the basin's major shale gas plays. The basin is home to the Marcellus Shale, as well as the Huron and Chattanooga Shales.

From the stimulation of the Marcellus discovery well in October of 2004, the Renz#1, to the present day, Universal continues to add purpose built equipment that incorporates the experience and knowledge we have gained from operating successfully for the past thirty years. Our team of engineers, geologists, technicians, and operating personnel work to design and perform jobs efficiently, effectively, and economically, which has earned us the respect of our customer base. Our hydraulic fracturing, nitrogen fracturing, acidizing and cementing capabilities, as well as flowback and slickline services enable us to serve many of our customers needs. Our fleet of quintiplex frac pumpers, 140 BPM blenders, and satellite equipped frac vans allow us to efficiently perform complex shale frac jobs.

We continue to add capacity in a controlled fashion that allows us to train crews and develop personnel. Training remains an essential part of our strategy to meet safety and quality standards. Our in-house Advanced Leadership Training is helping accelerate the development of management skills of our operators, foremen, and managers.

The long term advantages of natural gas usage and the proximity of the Marcellus to a large population of natural gas consumers, makes this an ideal region to grow our already substantial position. In the Huron and Chattanooga Shales, Universal's complement of high rate nitrogen pumping equipment gives us the ability to perform the larger stimulation projects, which is the key to unlocking the natural gas from these plays.

Financial Review

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

or

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

For the transition period from to

Commission File Number 0-22664

Patterson-UTI Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**75-2504748** *(I.R.S. Employer Identification No.)*
450 Gears Road, Suite 500, Houston, Texas *(Address of principal executive offices)*	**77067** *(Zip Code)*

Registrant's telephone number, including area code:
(281) 765-7100

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, $0.01 Par Value	The Nasdaq Global Select Market
Preferred Share Purchase Rights	The Nasdaq Global Select Market

Securities Registered Pursuant to Section 12(g) of the Act:
None

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

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2009, the last business day of the registrant's most recently completed second fiscal quarter, was $1,944,259,033, calculated by reference to the closing price of $12.86 for the common stock on the Nasdaq Global Select Market on that date.

As of February 17, 2010, the registrant had outstanding 153,567,174 shares of common stock, $.01 par value, its only class of common stock.

Documents incorporated by reference:

Portions of the registrant's definitive proxy statement for the 2010 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Report") and other public filings and press releases by us contain "forward-looking statements" within the meaning of the Securities Act of 1933, as amended (the "Securities Act"), the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the Private Securities Litigation Reform Act of 1995, as amended. These "forward-looking statements" involve risk and uncertainty. These forward-looking statements include, without limitation, statements relating to: liquidity; financing of operations; continued volatility of oil and natural gas prices; source and sufficiency of funds required for immediate capital needs and additional rig acquisitions (if further opportunities arise); impact of inflation; demand for our services; and other matters. Our forward-looking statements can be identified by the fact that they do not relate strictly to historic or current facts and often use words such as "believes," "budgeted," "continue," "expects," "estimates," "project," "will," "could," "may," "plans," "intends," "strategy," or "anticipates," or the negative thereof or other words and expressions of similar meaning. The forward-looking statements are based on certain assumptions and analyses we make in light of our experience and our perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Forward-looking statements may be made orally or in writing, including, but not limited to, Management's Discussion and Analysis of Financial Condition and Results of Operations included in this Report and other sections of our filings with the United States Securities and Exchange Commission (the "SEC") under the Exchange Act and the Securities Act.

Forward-looking statements are not guarantees of future performance and a variety of factors could cause actual results to differ materially from the anticipated or expected results expressed in or suggested by these forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, deterioration of global economic conditions, declines in oil and natural gas prices that could adversely affect demand for our services and their associated effect on day rates, rig utilization and planned capital expenditures, excess availability of land drilling rigs, including as a result of the reactivation or construction of new land drilling rigs, adverse industry conditions, adverse credit and equity market conditions, difficulty in integrating acquisitions, demand for oil and natural gas, shortages of rig equipment, governmental regulation and ability to retain management and field personnel. Refer to "Risk Factors" contained in Part 1 of this Report for a more complete discussion of these and other factors that might affect our performance and financial results. You are cautioned not to place undue reliance on any of our forward-looking statements. These forward-looking statements are intended to relay our expectations about the future, and speak only as of the date they are made. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, changes in internal estimates or otherwise.

PART I

Item 1. *Business*

Available Information

This Report, along with our Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, are available free of charge through our Internet website (www.patenergy.com) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on our website is not part of this Report or other filings that we make with the SEC. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Overview

We own and operate one of the largest fleets of land-based drilling rigs in the United States. The Company was formed in 1978 and reincorporated in 1993 as a Delaware corporation. Our contract drilling business operates primarily in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada.

As of December 31, 2009, we had a drilling fleet that consisted of 341 marketable land-based drilling rigs. A drilling rig includes the structure, power source and machinery necessary to cause a drill bit to penetrate the earth to a depth desired by the customer. A drilling rig is considered marketable at a point in time if it is operating or can be made ready to operate without significant capital expenditures. We also have a substantial inventory of drill pipe and drilling rig components.

We provide pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. These services consist primarily of well stimulation and cementing for completion of new wells and remedial work on existing wells. We also own and invest in oil and natural gas assets as a working interest owner. Our oil and natural gas interests are located primarily in Texas and New Mexico.

Prior to January 20, 2010, we provided drilling fluids, completion fluids and related services to oil and natural gas operators offshore in the Gulf of Mexico and on land in Texas, New Mexico, Oklahoma and Louisiana. We exited the drilling and completion fluids services business on January 20, 2010 and sold substantially all of the assets, other than billed accounts receivable, of that business.

Industry Segments

Our revenues, operating profits and identifiable assets have been primarily attributable to four industry segments:

- contract drilling services,
- pressure pumping services,
- oil and natural gas exploration and production, and.
- drilling and completion fluids services.

On January 20, 2010, we exited the drilling and completion fluids services business and ceased operations in that segment. As a result of the sale of this business, the historical results of operations for this segment have been reclassified and are presented as discontinued operations in this Report.

All of our industry segments had operating profits in 2007. In 2008, except for our drilling and completion fluids services segment, all of our industry segments had operating profits. In 2009, our pressure pumping services and oil and natural gas exploration and production segments had operating profits and our contract drilling services segment had an operating loss.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 15 of Notes to Consolidated Financial Statements included as a part of Items 7 and 8, respectively, of this Report for financial information pertaining to these industry segments.

Contract Drilling Operations

General — We market our contract drilling services to major and independent oil and natural gas operators. As of December 31, 2009, we had 341 marketable land-based drilling rigs based in the following regions:

- 73 in west Texas and southeastern New Mexico,
- 100 in north central and east Texas, northern Louisiana and Mississippi,
- 56 in the Rocky Mountain region (Colorado, Utah, Wyoming, Montana and North Dakota),
- 49 in south Texas and southern Louisiana,

• 28 in the Texas panhandle, Oklahoma and Arkansas,

• 15 in the Appalachian Basin, and

• 20 in western Canada.

Our marketable drilling rigs have rated maximum depth capabilities ranging from 5,000 feet to 30,000 feet. Of these drilling rigs, 107 are electric rigs and 234 are mechanical rigs. An electric rig differs from a mechanical rig in that the electric rig converts the diesel power (the sole energy source for a mechanical rig) into electricity to power the rig. We also have a substantial inventory of drill pipe and drilling rig components, which may be used in the activation of additional drilling rigs or as replacement parts for marketable rigs.

Drilling rigs are typically equipped with engines, drawworks, masts, pumps to circulate the drilling fluid, blowout preventers, drill pipe and other related equipment. Over time, components on a drilling rig are replaced or rebuilt. We spend significant funds each year as part of a program to modify, upgrade and maintain our drilling rigs to ensure that our drilling equipment is competitive. We have spent $1.3 billion during the last three years on capital expenditures to (1) build new land drilling rigs and (2) modify, upgrade and maintain our drilling fleet. During fiscal years 2009, 2008 and 2007, we spent approximately $395 million, $361 million and $540 million, respectively, on these capital expenditures.

Depth and complexity of the well and drill site conditions are the principal factors in determining the specifications of the rig selected for a particular job.

Our contract drilling operations depend on the availability of drill pipe, drill bits, replacement parts and other related rig equipment, fuel and qualified personnel. Some of these have been in short supply from time to time.

Drilling Contracts — Most of our drilling contracts are with established customers on a competitive bid or negotiated basis. Our drilling contracts are either on a well-to-well basis or a term basis. Well-to-well contracts are generally short-term in nature and cover the drilling of a single well or a series of wells. Term contracts are entered into for a specified period of time (frequently one to three years) and provide for the use of the drilling rig to drill multiple wells. During 2009, our average number of days to drill a well (which includes moving to the drill site, rigging up and rigging down) was approximately 20 days.

Our drilling contracts obligate us to provide and operate a drilling rig and to pay certain operating expenses, including wages of drilling personnel and necessary maintenance expenses. Most drilling contracts are subject to termination by the customer on short notice and may or may not contain provisions for the payment of an early termination fee to us in the event that the contract is terminated by the customer. Generally, we indemnify our customers against claims by our employees and claims that might arise from surface pollution caused by spills of fuel, lubricants and other solvents within our control. Generally, the customers indemnify us against claims that might arise from other surface and subsurface pollution. Each drilling contract contains the actual terms setting forth our rights and obligations and those of the customer, any of which rights and obligations may deviate from what is customary due to industry conditions or other factors.

Our drilling contracts provide for payment on a daywork, footage, or turnkey basis, or a combination thereof. In each case, we provide the rig and crews. Except for two wells drilled under footage contracts in 2009, all of the wells drilled during the years ended December 31, 2009, 2008 and 2007 were drilled under daywork contracts. Our bid for each job depends upon location, depth and anticipated complexity of the well, on-site drilling conditions, equipment to be used, estimated risks involved, estimated duration of the job, availability of drilling rigs and other factors particular to each proposed well.

Under daywork contracts, we provide the drilling rig and crew to the customer. The customer supervises the drilling of the well. Our compensation is based on a contracted rate per day during the period the drilling rig is utilized. We often receive a lower rate when the drilling rig is moving or when drilling operations are interrupted or restricted by adverse weather conditions or other conditions beyond our control. Daywork contracts typically provide separately for mobilization of the drilling rig. Except for two wells drilled under footage contracts in 2009, all of the wells we drilled in 2009, 2008 and 2007 were under daywork contracts.

Under footage contracts, we contract to drill a well to a certain depth under specified conditions for a fixed price per foot. The customer provides drilling fluids, casing, cementing and well design expertise. These contracts require us to bear the cost of services and supplies that we provide until the well has been drilled to the agreed depth. If we drill the well in less time than estimated, we have the opportunity to improve our profits over those that would be attainable under a daywork contract. Profits are reduced and losses may be incurred if the well requires more days to drill to the contracted depth than estimated. Footage contracts generally contain greater risks for a drilling contractor than daywork contracts. Under footage contracts, the drilling contractor typically assumes certain risks associated with loss of the well from fire, blowouts and other risks. We drilled two wells under footage contracts in 2009, and we did not drill any wells under footage contracts in 2008 or 2007.

Under turnkey contracts, we contract to drill a well to a certain depth under specified conditions for a fixed fee. In a turnkey arrangement, we are required to bear the costs of services, supplies and equipment beyond those typically provided under a footage contract. In addition to the drilling rig and crew, we are required to provide the drilling and completion fluids, casing, cementing, and the technical well design and engineering services during the drilling process. We also typically assume certain risks associated with drilling the well such as fires, blowouts, cratering of the well bore and other such risks. Compensation occurs only when the agreed scope of the work has been completed, which requires us to make larger up-front working capital commitments prior to receiving payments under a turnkey drilling contract. Under a turnkey contract, we have the opportunity to improve our profits if the drilling process goes as expected and there are no complications or time delays. Given the increased exposure we have under a turnkey contract, however, profits can be significantly reduced and losses can be incurred if complications or delays occur during the drilling process. Turnkey contracts generally involve the highest degree of risk among the three different types of drilling contracts. Although we have entered into turnkey contracts in the past, we did not enter into any turnkey contracts in the past three years.

Contract Drilling Activity — Information regarding our contract drilling activity for the last three years follows:

	Year Ended December 31,		
	2009	**2008**	**2007**
Average rigs operating per day(1)	91	254	244
Number of rigs operated during the year	243	315	338
Number of wells drilled during the year	1,539	4,218	4,237
Number of operating days(2)	33,394	93,068	89,095

(1) A rig is considered to be operating if it is earning revenue pursuant to a contract on a given day.

(2) Includes standby days under term contracts where revenue was earned but the rig was not working. The number of these standby days under term contracts was 2,070 in 2009, 486 in 2008 and zero in 2007.

Drilling Rigs and Related Equipment — We estimate the depth capacity with respect to our marketable rigs as of December 31, 2009 to be as follows:

	Number of Rigs		
Depth Rating (Ft.)	**U.S.**	**Canada**	**Total**
5,000 to 7,999	—	3	3
8,000 to 11,999	59	9	68
12,000 to 15,999	189	8	197
16,000 to 30,000	73	—	73
Totals	321	20	341

At December 31, 2009, we owned and operated 323 trucks and 417 trailers used to rig down, transport and rig up our drilling rigs. Our ownership of trucks and trailers reduces our dependency upon third parties for these services and generally enhances the efficiency of our contract drilling operations, particularly in periods of high drilling rig utilization.

Most repair and overhaul work to our drilling rig equipment is performed at our yard facilities located in Texas, Oklahoma, Wyoming, Utah, Pennsylvania and western Canada.

Pressure Pumping Operations

General — We provide pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. Pressure pumping services are primarily well stimulation and cementing for the completion of new wells and remedial work on existing wells. Most wells drilled in the Appalachian Basin require some form of fracturing or other stimulation to enhance the flow of oil and natural gas by pumping fluids under pressure into the well bore. Appalachian Basin wells typically require cementing services. The cementing process inserts material between the wall of the well bore and the casing to center and stabilize the casing.

Equipment — Our pressure pumping equipment at December 31, 2009 includes equipment used in providing hydraulic and nitrogen fracturing services as well as cementing services as follows:

Hydraulic fracturing equipment:

- 20 quintiplex pump trailers (45,000 hydraulic horsepower),
- 69 triplex pumper trucks (82,800 hydraulic horsepower),
- 35 blender trucks,
- 4 blender trailers,
- 32 bulk acid trucks/acid pumper trucks,
- 70 bulk sand trucks,
- 19 sand pneumatic trucks,
- 6 sand pneumatic trailers,
- 15 flatbed material trucks,
- 30 connection trucks,
- 1 shale fracturing hydration trailer,
- 3 shale fracturing manifold trailers,
- 1 shale fracturing iron trailer,
- 15 shale fracturing sand field bins with conveyors, and
- 3 shale fracturing large conveyors.

Nitrogen fracturing equipment:

- 59 nitrogen pumper trucks (35,400 hydraulic horsepower),
- 30 bulk nitrogen trucks, and
- 9 bulk nitrogen tractor trailer combinations,

Cementing equipment:

- 44 cement pumper trucks, and
- 51 bulk cement trucks.

In addition to the equipment listed above, we had 45 tractors at December 31, 2009 which are used in all of the lines of business within our pressure pumping segment.

Oil and Natural Gas Interests

We have been engaged in the development, exploration, acquisition and production of oil and natural gas. Through October 31, 2007, we served as operator with respect to several properties and were actively involved in the development, exploration, acquisition and production of oil and natural gas. Effective November 1, 2007, we sold the related operations portion of our exploration and production business, which was the portion of our business that actively managed the development, exploration, acquisition and production of oil and natural gas. We continue to own and invest in oil and natural gas assets as a working interest owner. Our oil and natural gas interests are located primarily in producing regions of Texas and New Mexico.

Drilling and Completion Fluids Operations

Prior to exiting the business in January 2010, we provided drilling fluids, completion fluids and related services to oil and natural gas operators offshore in the Gulf of Mexico and on land in Texas, New Mexico, Oklahoma and Louisiana.

Customers

The customers of each of our oil and natural gas service business segments are oil and natural gas operators. Our customer base includes both major and independent oil and natural gas operators. During 2009, no single customer accounted for 10% or more of our consolidated operating revenues.

Competition

Our contract drilling and pressure pumping businesses are highly competitive. Historically, available equipment used in these businesses has frequently exceeded demand in our markets. The price for our services is a key competitive factor in our markets, in part because equipment used in our businesses can be moved from one area to another in response to market conditions. In addition to price, we believe availability and condition of equipment, quality of personnel, service quality and safety record are key factors in determining which contractor is awarded a job in the markets in which we operate. We expect that the market for land drilling and pressure pumping services will continue to be competitive.

Government and Environmental Regulation

All of our operations and facilities are subject to numerous Federal, state, foreign, and local laws, rules and regulations related to various aspects of our business, including:

- drilling of oil and natural gas wells,
- the relationships with our employees,
- containment and disposal of hazardous materials, oilfield waste, other waste materials and acids,
- use of underground storage tanks, and
- use of underground injection wells.

To date, applicable environmental laws and regulations in the United States and Canada have not required the expenditure of significant resources outside the ordinary course of business. We do not anticipate any material capital expenditures for environmental control facilities or extraordinary expenditures to comply with environmental rules and regulations in the foreseeable future. However, compliance costs under existing laws or under any new requirements could become material, and we could incur liability in any instance of noncompliance.

Our business is generally affected by political developments and by Federal, state, foreign, and local laws and regulations that relate to the oil and natural gas industry. The adoption of laws and regulations affecting the oil and natural gas industry for economic, environmental and other policy reasons could increase costs relating to drilling and production. They could have an adverse effect on our operations. Federal, state, foreign and local environmental laws and regulations currently apply to our operations and may become more stringent in the future.

We believe we use operating and disposal practices that are standard in the industry. However, hydrocarbons and other materials may have been disposed of or released in or under properties currently or formerly owned or operated by us or our predecessors which may have resulted, or may result, in soil and groundwater contamination in certain locations. Any contamination found on, under or originating from the properties may be subject to remediation requirements under Federal, state, foreign and local laws and regulations. In addition, some of these properties have been operated by third parties over whom we have no control of their treatment of hydrocarbon and other materials or the manner in which they may have disposed of or released such materials. We could be required to remove or remediate wastes disposed of or released by prior owners or operators. In addition, it is possible we could be held responsible for oil and natural gas properties in which we own an interest but are not the operator.

Some of the environmental laws and regulations that are applicable to our business operations are discussed in the following paragraphs, but the discussion does not cover all environmental laws and regulations that govern our operations.

In the United States, the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980, as amended, commonly known as CERCLA, and comparable state statutes impose strict liability on:

- owners and operators of sites, and
- persons who disposed of or arranged for the disposal of "hazardous substances" found at sites.

The Federal Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes govern the disposal of "hazardous wastes." Although CERCLA currently excludes petroleum from the definition of "hazardous substances," and RCRA also excludes certain classes of exploration and production wastes from regulation, such exemptions by Congress under both CERCLA and RCRA may be deleted, limited, or modified in the future. If such changes are made to CERCLA and/or RCRA, we could be required to remove and remediate previously disposed of materials (including materials disposed of or released by prior owners or operators) from properties (including ground water contaminated with hydrocarbons) and to perform removal or remedial actions to prevent future contamination.

The Federal Water Pollution Control Act and the Oil Pollution Act of 1990, as amended, and implementing regulations govern:

- the prevention of discharges, including oil and produced water spills, and
- liability for drainage into waters.

The Oil Pollution Act imposes strict liability for a comprehensive and expansive list of damages from an oil spill into waters from facilities. Liability may be imposed for oil removal costs and a variety of public and private damages. Penalties may also be imposed for violation of Federal safety, construction and operating regulations, and for failure to report a spill or to cooperate fully in a clean-up.

The Oil Pollution Act also expands the authority and capability of the Federal government to direct and manage oil spill clean-up and operations, and requires operators to prepare oil spill response plans in cases where it can reasonably be expected that substantial harm will be done to the environment by discharges on or into navigable waters. We have spill prevention control and countermeasure plans in place for our working interest in oil and natural gas properties in each of the areas in which these interests are located. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party, such as us, to civil or criminal actions. Although the liability for owners and operators is the same under the Federal Water Pollution Act, the damages recoverable under the Oil Pollution Act are potentially much greater and can include natural resource damages.

In Canada, a variety of Canadian federal, provincial and municipal laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and wastes and in connection with spills, releases and emissions of various substances to the environment. These laws and regulations also require that facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, new projects or changes to existing projects may require the submission and approval of environmental assessments or permit applications. These laws and regulations are subject to frequent change, and the clear trend is to place increasingly stringent limitations on activities that may affect the environment.

Our operations are also subject to Federal, state, foreign and local laws, rules and regulations for the control of air emissions, including the Federal Clean Air Act and the Canadian Environmental Protection Act. We are aware of the increasing focus of local, state, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change issues. We are also aware of legislation proposed by United States lawmakers and the Canadian legislature to reduce GHG emissions, as well as GHG emissions regulations enacted by the U.S. Environmental Protection Agency and the Canadian provinces of Alberta and British Columbia. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition.

Risks and Insurance

Our operations are subject to the many hazards inherent in the drilling business, including:

- accidents at the work location,
- blow-outs,
- cratering,
- fires, and
- explosions.

These hazards could cause:

- personal injury or death,
- suspension of drilling operations, or
- serious damage or destruction of the equipment involved and, in addition to environmental damage, could cause substantial damage to producing formations and surrounding areas.

Damage to the environment, including property contamination in the form of either soil or ground water contamination, could also result from our operations, particularly through:

- oil or produced water spillage,
- natural gas leaks, and
- fires.

In addition, we could become subject to liability for reservoir damages. The occurrence of a significant event, including pollution or environmental damages, could materially affect our operations, cash flows and financial condition.

As a protection against operating hazards, we maintain insurance coverage we believe to be adequate, including:

- insurance for fire, windstorm and other risks of physical loss to our rigs and other assets,
- employer's liability,
- automobile liability,
- commercial general liability insurance, and
- workers compensation insurance.

We believe that we are adequately insured for bodily injury and property damage to others with respect to our operations. Such insurance, however, may not be sufficient to protect us against liability for all consequences of:

- personal injury,
- well disasters,
- extensive fire damage,
- damage to the environment, or
- other hazards.

We also carry insurance to cover physical damage to, or loss of, our drilling rigs. Such insurance does not, however, cover the full replacement cost of the rigs, and we do not carry insurance against loss of earnings resulting from such damage. In view of the difficulties that may be encountered in renewing such insurance at reasonable rates, no assurance can be given that:

- we will be able to maintain the type and amount of coverage that we believe to be adequate at reasonable rates, or

- any particular types of coverage will be available.

In addition to insurance coverage, we also attempt to obtain indemnification from our customers for certain risks. These indemnity agreements typically require our customers to hold us harmless in the event of loss of production or reservoir damage. These contractual indemnifications, if obtained, may not be supported by adequate insurance maintained by the customer.

Employees

We had approximately 4,200 full-time employees at December 31, 2009. The number of employees fluctuates depending on the current and expected demand for our services. We consider our employee relations to be satisfactory. None of our employees are represented by a union.

Seasonality

Seasonality does not significantly affect our overall operations. However, our drilling operations in Canada and, to a lesser extent, our pressure pumping operations in the Appalachian Basin, are subject to slow periods of activity during the Spring thaw.

Raw Materials and Subcontractors

We use many suppliers of raw materials and services. These materials and services have historically been available, although there is no assurance that such materials and services will continue to be available on favorable terms or at all. We also utilize numerous independent subcontractors from various trades.

Item 1A. *Risk Factors.*

You should consider each of the following factors as well as the other information in this Report in evaluating our business and our prospects. Additional risks and uncertainties not presently known to us or that we currently consider immaterial may also impair our business operations. If any of the following risks actually occur, our business and financial results could be harmed. You should also refer to the other information set forth in this Report, including our financial statements and the related notes.

Global Economic Conditions May Adversely Affect Our Operating Results.

Since reaching a peak in June 2008, there has been a significant decline in oil and natural gas prices. Since that time there has also been a significant deterioration in the global economic environment. As part of this deterioration, there has been significant uncertainty in the capital markets and access to financing has been reduced. Due to these conditions, our customers reduced or curtailed their drilling programs, which resulted in a decrease in demand for our services. Furthermore, these factors have resulted in, and could continue to result in, certain of our customers experiencing an inability to pay suppliers, including us, if they are not able to access capital to fund their operations. Although the significant deterioration in the global economic environment appears to have recently stabilized to some degree, our customers may not substantially increase their drilling programs unless there is more certainty about global economic prospects. These conditions could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We are Dependent on the Oil and Natural Gas Industry and Market Prices for Oil and Natural Gas. Declines in Oil and Natural Gas Prices Have Adversely Affected Our Operating Results.

Our revenue, profitability, financial condition and rate of growth are substantially dependent upon prevailing prices for natural gas and, to a lesser extent, oil. For many years, oil and natural gas prices and markets have been extremely volatile. Prices are affected by:

- market supply and demand,
- international military, political and economic conditions, and
- the ability of the Organization of Petroleum Exporting Countries, commonly known as OPEC, to set and maintain production and price targets.

All of these factors are beyond our control. During 2008, the monthly average market price of natural gas peaked in June at $13.06 per Mcf before rapidly declining to an average of $5.99 per Mcf in December 2008. In 2009, the monthly average market price of natural gas declined further to a low of $3.06 per Mcf in September. This decline in the market price of natural gas resulted in our customers significantly reducing their drilling activities beginning in the fourth quarter of 2008, and drilling activities remained low throughout 2009. This reduction in demand combined with the reactivation and construction of new land drilling rigs in the United States during the last several years has resulted in excess capacity compared to demand. As a result of these factors, our average number of rigs operating has declined significantly. We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Low market prices for natural gas would likely result in demand for our drilling rigs remaining low and adversely affect our operating results, financial condition and cash flows.

A General Excess of Operable Land Drilling Rigs and Increasing Rig Specialization May Adversely Affect Our Utilization and Profit Margins.

The North American land drilling industry has experienced periods of downturn in demand over the last decade. During these periods, there have been substantially more drilling rigs available than necessary to meet demand. As a result, drilling contractors have had difficulty sustaining profit margins and, at times, have sustained losses during the downturn periods.

In addition, unconventional resource plays have substantially increased recently and some drilling rigs are not capable of drilling these wells efficiently. Accordingly, the utilization of some older technology drilling rigs may be hampered by their lack of capability to successfully compete for this work. Other ongoing factors which could continue to adversely affect utilization rates and pricing, even in an environment of high oil and natural gas prices and increased drilling activity, include:

- movement of drilling rigs from region to region,
- reactivation of land-based drilling rigs, or
- construction of new drilling rigs.

Construction of new drilling rigs increased significantly during the last five years. The addition of new drilling rigs to the market and the recent decrease in demand has resulted in excess capacity. We cannot predict either the future level of demand for our contract drilling services or future conditions in the oil and natural gas contract drilling business.

Shortages of Drill Pipe, Replacement Parts and Other Related Rig Equipment Adversely Affects Our Operating Results.

During periods of increased demand for drilling services, the industry has experienced shortages of drill pipe, replacement parts and other related rig equipment. These shortages can cause the price of these items to increase significantly and require that orders for the items be placed well in advance of expected use. In addition, any interruption in supply due to vendor or other issues could result in significant delays in delivery of equipment. These price increases and delays in delivery may require us to increase capital and repair expenditures in our contract drilling segment. Severe shortages or delays in delivery could limit our ability to operate our drilling rigs.

The Oil Service Business Segments in Which We Operate Are Highly Competitive with Excess Capacity, which Adversely Affects Our Operating Results.

Our land drilling and pressure pumping businesses are highly competitive. At times, available land drilling rigs and pressure pumping equipment exceed the demand for such equipment. This excess capacity has resulted in substantial competition for drilling and pressure pumping contracts. The fact that drilling rigs and pressure pumping equipment are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry.

We believe that price competition for drilling and pressure pumping contracts will continue due to the existence of available rigs and pressure pumping equipment.

In recent years, many drilling and pressure pumping companies have consolidated or merged with other companies. Although this consolidation has decreased the total number of competitors, we believe the competition for drilling and pressure pumping services will continue to be intense.

Labor Shortages and Rising Labor Costs Adversely Affect Our Operating Results.

During periods of increasing demand for contract drilling and pressure pumping services, the industry experiences shortages of qualified personnel. During these periods, our ability to attract and retain sufficient qualified personnel to market and operate our drilling rigs and pressure pumping equipment is adversely affected, which negatively impacts both our operations and profitability. Operationally, it is more difficult to hire qualified personnel, which adversely affects our ability to mobilize inactive rigs and pressure pumping equipment in response to the increased demand for such services. Additionally, wage rates for drilling and pressure pumping personnel are likely to increase during periods of increasing demand, resulting in higher operating costs.

Growth Through the Building of New Rigs and Rig Acquisitions are Not Assured.

We have increased our drilling rig fleet in the past through mergers, acquisitions and rig construction. The land drilling industry has experienced significant consolidation, and there can be no assurance that acquisition opportunities will be available in the future. We are also likely to continue to face intense competition from other companies for available acquisition opportunities. In addition, because improved technology has enhanced the ability to recover oil and natural gas, contract drillers may continue to build new, high technology rigs.

There can be no assurance that we will:

- have sufficient capital resources to complete additional acquisitions or build new rigs,
- successfully integrate additional drilling rigs or other assets,
- effectively manage the growth and increased size of our organization and drilling fleet,
- successfully deploy idle, stacked or additional rigs,
- maintain the crews necessary to operate additional drilling rigs, or
- successfully improve our financial condition, results of operations, business or prospects as a result of any completed acquisition or the building of new drilling rigs.

We may incur substantial indebtedness to finance future acquisitions or build new drilling rigs and also may issue equity, convertible or debt securities in connection with any such acquisitions or building program. Debt service requirements could represent a significant burden on our results of operations and financial condition, and the issuance of additional equity would be dilutive to existing stockholders. Also, continued growth could strain our management, operations, employees and other resources.

The Nature of our Business Operations Presents Inherent Risks of Loss that, if not Insured or Indemnified Against, Could Adversely Affect Our Operating Results.

Our operations are subject to many hazards inherent in the contract drilling and pressure pumping businesses, which in turn could cause personal injury or death, work stoppage, or serious damage to our equipment. Our operations could also cause environmental and reservoir damages. We maintain insurance coverage and have indemnification agreements with many of our customers. However, there is no assurance that such insurance or indemnification agreements would adequately protect us against liability or losses from all consequences of these hazards. Additionally, there can be no assurance that insurance would be available to cover any or all of these risks, or, even if available, that insurance premiums or other costs would not rise significantly in the future, so as to make the cost of such insurance prohibitive. Incurring a liability for which we are not fully insured or indemnified could materially affect our business, financial condition and results of operations.

We have also elected in some cases to accept a greater amount of risk through increased deductibles on certain insurance policies. For example, we maintain a $1.0 million per occurrence deductible on our workers' compensation, general liability and equipment insurance coverages.

Violations of Environmental Laws and Regulations Could Materially Adversely Affect Our Operating Results.

All of our operations and facilities are subject to numerous Federal, state, foreign and local environmental laws, rules and regulations, including, without limitation, laws concerning the containment and disposal of hazardous substances, oil field waste and other waste materials, the use of underground storage tanks, and the use of underground injection wells. The cost of compliance with these laws and regulations could be substantial. A failure to comply with these requirements could expose us to substantial civil and criminal penalties. In addition, environmental laws and regulations in the United States and Canada impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages from such spills. As an owner and operator of land-based drilling rigs, we may be deemed to be a responsible party under these laws and regulations.

We are aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. We are also aware of legislation proposed by United States lawmakers and the Canadian legislature to reduce GHG emissions, as well as GHG emissions regulations enacted by the U.S. Environmental Protection Agency and the Canadian provinces of Alberta and British Columbia. We will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact of GHG emissions and climate change on our operations and take appropriate actions, where necessary. Any direct and indirect costs of meeting these requirements may adversely affect our business, results of operations and financial condition.

Anti-takeover Measures in Our Charter Documents and Under State Law Could Discourage an Acquisition and Thereby Affect the Related Purchase Price.

We are a Delaware corporation subject to the Delaware General Corporation Law, including Section 203, an anti-takeover law. We have also enacted certain anti-takeover measures, including a stockholders' rights plan. In addition, our Board of Directors has the authority to issue up to one million shares of preferred stock and to determine the price, rights (including voting rights), conversion ratios, preferences and privileges of that stock without further vote or action by the holders of the common stock. As a result of these measures and others, potential acquirers might find it more difficult or be discouraged from attempting to effect an acquisition transaction with us. This may deprive holders of our securities of certain opportunities to sell or otherwise dispose of the securities at above-market prices pursuant to any such transactions.

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

None.

Item 2. *Properties*

Our corporate headquarters comprises approximately 12,000 square feet of leased office space, and is located at 450 Gears Road, Suite 500, Houston, Texas. Our telephone number at that address is (281) 765-7100. Our primary administrative office is located in Snyder, Texas and includes approximately 37,000 square feet of office and storage space.

Contract Drilling Operations — Our drilling services are supported by several offices and yard facilities located throughout our areas of operations, including Texas, New Mexico, Oklahoma, Colorado, Utah, Wyoming, Pennsylvania and western Canada.

Pressure Pumping — Our pressure pumping services are supported by several offices and yard facilities located throughout our areas of operations including Pennsylvania, Ohio, New York, West Virginia, Kentucky, Tennessee and Colorado.

Oil and Natural Gas Working Interests — Our interests in oil and natural gas properties are primarily located in Texas and New Mexico.

We own our administrative offices in Snyder, Texas, as well as several of our other facilities. We also lease a number of facilities, and we do not believe that any one of the leased facilities is individually material to our operations. We believe that our existing facilities are suitable and adequate to meet our needs.

Item 3. *Legal Proceedings.*

We are party to various legal proceedings arising in the normal course of our business. We do not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on our results of operations, cash flows or financial condition.

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.*

(a) Market Information

Our common stock, par value $0.01 per share, is publicly traded on the Nasdaq Global Select Market and is quoted under the symbol "PTEN." Our common stock is included in the S&P MidCap 400 Index and several other market indices. The following table provides high and low sales prices of our common stock for the periods indicated:

	High	Low
2008:		
First quarter	$26.38	$17.40
Second quarter	36.40	25.71
Third quarter	37.45	17.85
Fourth quarter	19.64	8.64
2009:		
First quarter	$13.50	$ 7.49
Second quarter	15.95	8.56
Third quarter	15.98	11.38
Fourth quarter	18.07	14.20

(b) Holders

As of February 17, 2010, there were approximately 1,700 holders of record of our common stock.

(c) Dividends

We paid cash dividends during the years ended December 31, 2008 and 2009 as follows:

	Per Share	Total (in thousands)
2008:		
Paid on March 28, 2008	$0.12	$18,493
Paid on June 27, 2008	0.16	25,011
Paid on September 29, 2008	0.16	24,803
Paid on December 29, 2008	0.16	24,558
Total cash dividends	$0.60	$92,865
2009:		
Paid on March 31, 2009	$0.05	$ 7,655
Paid on June 30, 2009	0.05	7,675
Paid on September 30, 2009	0.05	7,675
Paid on December 30, 2009	0.05	7,676
Total cash dividends	$0.20	$30,681

On February 10, 2010, our Board of Directors approved a cash dividend on our common stock in the amount of $0.05 per share to be paid on March 30, 2010 to holders of record as of March 15, 2010. The amount and timing of all future dividend payments, if any, is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our credit facilities and other factors.

(d) Securities Authorized for Issuance Under Equity Compensation Plans

Equity compensation plan information as of December 31, 2009 follows:

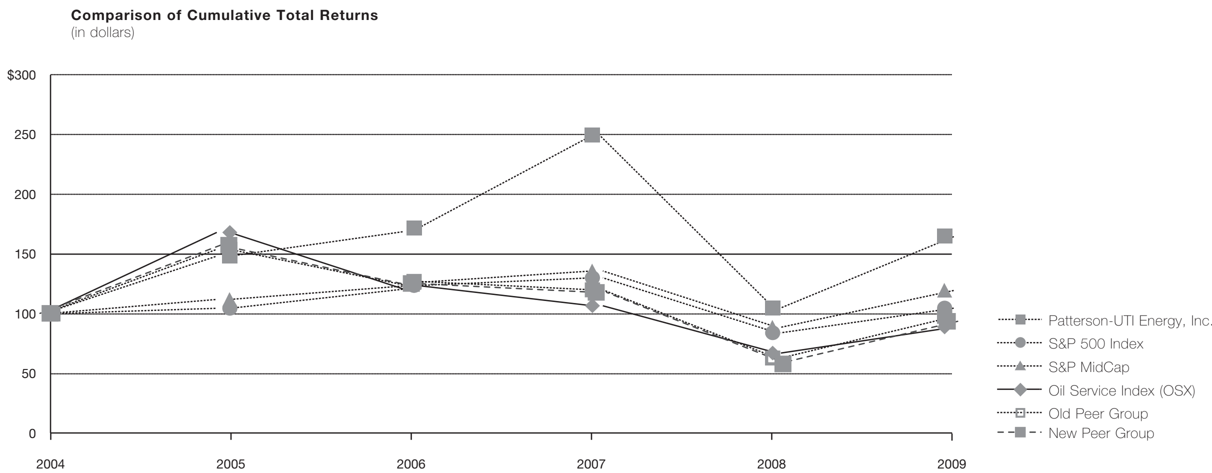
	Equity Compensation Plan Information		
Plan Category	**Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights**	**Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights**	**Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column(a))**
	(a)	**(b)**	**(c)**
Equity compensation plans approved by security holders(1)	6,627,634	$20.50	2,545,524
Equity compensation plans not approved by security holders(2)	214,136	$ 9.97	—
Total	6,841,770	$20.17	2,545,524

(1) The Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended (the "2005 Plan"), provides for awards of incentive stock options, non-incentive stock options, tandem and freestanding stock appreciation rights, restricted stock awards, other stock unit awards, performance share awards, performance unit awards and dividend equivalents to key employees, officers and directors, which are subject to certain vesting and forfeiture provisions. All options are granted with an exercise price equal to or greater than the fair market value of the common stock at the time of grant. The vesting schedule and term are set by the Compensation Committee of the Board of Directors. All securities remaining available for future issuance under equity compensation plans approved by security holders in column (c) are available under this plan.

(2) The Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan (the "2001 Plan") was approved by the Board of Directors in July 2001. In connection with the approval of the 2005 Plan, the Board of Directors approved a resolution that no further options, restricted stock or other awards would be granted under any equity compensation plan, other than the 2005 Plan. The terms of the 2001 Plan provided for grants of stock options, stock appreciation rights, shares of restricted stock and performance awards to eligible employees other than officers and directors. No Incentive Stock Options could be awarded under the 2001 Plan. All options were granted with an exercise price equal to or greater than the fair market value of the common stock at the time of grant. The vesting schedule and term were set by the Compensation Committee of the Board of Directors.

(e) Performance Graph

The following graph compares the cumulative stockholder return of our common stock for the period from December 31, 2004 through December 31, 2009, with the cumulative total return of the Standard & Poors 500 Stock Index, the Standard & Poors MidCap Index, the Oilfield Service Index and a peer group determined by us. Our 2008 peer group consists of BJ Services Company, Bronco Drilling Company, Inc., Helmerich & Payne, Inc., Nabors Industries, Ltd., Pioneer Drilling Co., Superior Well Services, Inc. and Unit Corp. We evaluated our peer group for 2009 and determined that it was appropriate to remove Unit Corp. from the peer group as their drilling revenue as a percentage of total revenue had fallen to a level that was no longer comparable to ours. All of the companies in our peer group are providers of land-based drilling or pressure pumping services. The graph assumes investment of $100 on December 31, 2004 and reinvestment of all dividends.



	Fiscal Year Ended December 31,					
Company/Index	**2004 ($)**	**2005 ($)**	**2006 ($)**	**2007 ($)**	**2008 ($)**	**2009 ($)**
Patterson-UTI Energy, Inc.	100.00	170.35	121.41	104.04	63.26	85.73
2008 Peer Group Index	100.00	155.75	125.07	117.78	58.99	94.96
2009 Peer Group Index	100.00	156.66	124.84	117.42	57.93	93.38
S&P 500 Stock Index	100.00	104.91	121.48	128.16	80.74	102.11
Oilfield Service Index (OSX)	100.00	149.90	171.09	251.13	102.21	164.12
S&P MidCap Index	100.00	112.56	124.17	134.08	85.50	117.46

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

Item 6. *Selected Financial Data.*

Our selected consolidated financial data as of December 31, 2009, 2008, 2007, 2006 and 2005, and for each of the five years in the period ended December 31, 2009 should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and related Notes thereto, included as Items 7 and 8, respectively, of this Report. Certain reclassifications have been made to the historical financial data to conform with the 2009 presentation. Due to the sale of substantially all of the assets of our drilling and completion fluids business in January 2010, the results of operations for that business have been reclassified and are presented as discontinued operations in all periods presented below.

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share amounts)				
Statement of Operations Data:					
Operating revenues:					
Contract drilling	$ 599,287	$1,804,026	$1,741,647	$2,169,370	$1,485,684
Pressure pumping	161,441	217,494	202,812	145,671	93,144
Oil and natural gas	21,218	42,360	41,637	39,187	39,616
Total	781,946	2,063,880	1,986,096	2,354,228	1,618,444
Operating costs and expenses:					
Contract drilling	357,742	1,038,327	963,150	1,002,001	776,313
Pressure pumping	111,414	132,570	105,273	77,755	54,956
Oil and natural gas	7,341	12,793	10,864	13,374	9,566
Depreciation, depletion and impairment	289,847	275,990	246,346	193,664	154,025
Selling, general and administrative	56,621	58,080	54,665	44,544	30,198
Embezzlement costs (recoveries)	—	—	(43,955)	3,081	20,043
Net loss (gain) on asset disposals	3,385	(4,163)	(16,432)	3,905	(1,200)
Other operating expenses	3,810	4,350	2,875	5,585	4,859
Total	830,160	1,517,947	1,322,786	1,343,909	1,048,760
Operating income (loss)	(48,214)	545,933	663,310	1,010,319	569,684
Other income (expense)	(3,341)	1,425	527	4,657	3,465
Income (loss) from continuing operations before income taxes	(51,555)	547,358	663,837	1,014,976	573,149
Income tax expense (benefit)	(17,595)	193,490	229,350	360,639	207,706
Income (loss) from continuing operations	$ (33,960)	$ 353,868	$ 434,487	$ 654,337	$ 365,443
Income (loss) from continuing operations per common share:					
Basic	$ (0.22)	$ 2.29	$ 2.78	$ 3.94	$ 2.14
Diluted	$ (0.22)	$ 2.27	$ 2.75	$ 3.89	$ 2.11
Cash dividends per common share	$ 0.20	$ 0.60	$ 0.44	$ 0.28	$ 0.16
Weighted average number of common shares outstanding:					
Basic	152,069	153,379	154,755	165,159	170,426
Diluted	152,069	154,358	156,612	167,200	172,312
Balance Sheet Data:					
Total assets	$2,662,152	$2,712,817	$2,465,199	$2,192,503	$1,795,781
Borrowings under line of credit	—	—	50,000	120,000	—
Stockholders' equity	2,081,700	2,126,942	1,896,030	1,562,466	1,367,011
Working capital	263,960	338,761	227,577	335,052	382,448

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

Management Overview — We are a leading provider of contract services to the North American oil and natural gas industry. Our services primarily involve the drilling, on a contract basis, of land-based oil and natural gas wells and, to a lesser extent, pressure pumping services. In addition to the aforementioned contract services, we also invest, on a working interest basis, in oil and natural gas properties. For the three years ended December 31, 2009, our operating revenues consisted of the following (dollars in thousands):

	2009		2008		2007	
Contract drilling	$599,287	76%	$1,804,026	87%	$1,741,647	88%
Pressure pumping	161,441	21	217,494	11	202,812	10
Oil and natural gas	21,218	3	42,360	2	41,637	2
	$781,946	100%	$2,063,880	100%	$1,986,096	100%

We provide our contract services to oil and natural gas operators in many of the oil and natural gas producing regions of North America. Our contract drilling operations are focused in various regions of Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, South Dakota, Pennsylvania, and western Canada, while our pressure pumping services are focused primarily in the Appalachian Basin. The oil and natural gas properties in which we hold interests are primarily located in Texas and New Mexico.

Typically, the profitability of our business is most readily assessed by two primary indicators in our contract drilling segment: our average number of rigs operating and our average revenue per operating day. During 2009, our average number of rigs operating was 91 compared to 254 in 2008 and 244 in 2007. Our average revenue per operating day was $17,950 in 2009 compared to $19,380 in 2008 and $19,550 in 2007. We had a consolidated net loss of $38.3 million for 2009 compared to consolidated net income of $347 million for 2008. This decrease was primarily due to our contract drilling segment experiencing a significant decrease in the average number of rigs operating as compared to 2008.

Our revenues, profitability and cash flows are highly dependent upon prevailing prices for natural gas and, to a lesser extent, oil. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which generally results in increased demand for our contract services. Conversely, in periods when these commodity prices deteriorate, the demand for our contract services generally weakens and we experience downward pressure on pricing for our services. Since reaching a peak in June 2008, there has been a significant decline in oil and natural gas prices. Since that time there has also been a substantial deterioration in the global economic environment. As part of this deterioration, there has been substantial uncertainty in the capital markets and access to financing has been reduced. Due to these conditions, our customers reduced or curtailed their drilling programs, which resulted in a decrease in demand for our services, as evidenced by the decline in our monthly average rigs operating from a high of 283 in October 2008 to a low of 60 in June 2009 before partially recovering to 118 in December 2009. Furthermore, these factors have resulted in, and could continue to result in, certain of our customers experiencing an inability to pay suppliers, including us, if they are not able to access capital to fund their operations. We are also highly impacted by competition, the availability of excess equipment, labor issues and various other factors that could materially adversely affect our business, financial condition, cash flows and results of operations and which are more fully described above as "Risk Factors" in Item 1A of this Report.

We believe that the liquidity shown on our balance sheet as of December 31, 2009, which includes approximately $264 million in working capital (including $49.9 million in cash) and approximately $194 million available under our $240 million revolving credit facility, together with cash expected to be generated from operations (including expected income tax refunds in 2010 of approximately $114 million resulting from the carry-back of net operating losses), should provide us with sufficient ability to fund our current plans to build new equipment, make improvements to our existing equipment, expand into new regions, pay cash dividends and survive the current downturn in our industry. If we pursue opportunities for growth that require capital, we believe we would be able to satisfy these needs through a combination of working capital, cash generated from operations, borrowing capacity under our revolving credit facility or additional debt or equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

Commitments and Contingencies — As of December 31, 2009, we maintained letters of credit in the aggregate amount of $46.3 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire at various times during each calendar year and are typically renewed annually. As of December 31, 2009, no amounts had been drawn under the letters of credit.

As of December 31, 2009, we had commitments to purchase approximately $186 million of major equipment.

Trading and investing — We have not engaged in trading activities that include high-risk securities, such as derivatives and non-exchange traded contracts. We invest cash primarily in highly liquid, short-term investments such as overnight deposits and money market accounts.

Description of business — We conduct our contract drilling operations in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada. For the years ended December 31, 2009, 2008 and 2007, revenue earned in Canada was $45.4 million, $88.5 million and $72.9 million, respectively. Additionally, we had long-lived assets located in Canada of $69.2 million and $67.2 million as of December 31, 2009 and 2008, respectively. As of December 31, 2009, we had 341 marketable land-based drilling rigs. We provide pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. These services consist primarily of well stimulation and cementing for completion of new wells and remedial work on existing wells. Prior to the sale of substantially all of the assets of our drilling fluids business on January 20, 2010, we provided drilling fluids, completion fluids and related services to oil and natural gas operators offshore in the Gulf of Mexico and on land in Texas, New Mexico, Oklahoma and Louisiana. Drilling and completion fluids are used by oil and natural gas operators during the drilling process to control pressure when drilling oil and natural gas wells. Due to our exit from the drilling and completion fluids business in January 2010, we have presented the results of that operating segment as discontinued operations in this Report. We also invest, on a working interest basis, in oil and natural gas properties.

Critical Accounting Policies

In addition to established accounting policies, our consolidated financial statements are impacted by certain estimates and assumptions made by management. The following is a discussion of our critical accounting policies pertaining to property and equipment, oil and natural gas properties, goodwill, revenue recognition and the use of estimates.

Property and equipment — Property and equipment, including betterments which extend the useful life of the asset, are stated at cost. Maintenance and repairs are charged to expense when incurred. We provide for the depreciation of our property and equipment using the straight-line method over the estimated useful lives. Our method of depreciation does not change when equipment becomes idle; we continue to depreciate idled equipment on a straight-line basis. No provision for salvage value is considered in determining depreciation of our property and equipment. We review our long-lived assets, including property and equipment, for impairment whenever events or changes in circumstances indicate that the carrying values of certain assets may not be recovered over their estimated remaining useful lives. In connection with this review, assets are grouped at the lowest level at which identifiable cash flows are largely independent of other asset groupings. The cyclical nature of our industry has resulted in fluctuations in rig utilization over periods of time. Management believes that the contract drilling industry will continue to be cyclical and rig utilization will fluctuate. Based on management's expectations of future trends, we estimate future cash flows over the life of the respective assets in our assessment of impairment. These estimates of cash flows are based on historical cyclical trends in the industry as well as management's expectations regarding the continuation of these trends in the future. Provisions for asset impairment are charged against income when estimated future cash flows, on an undiscounted basis, are less than the asset's net book value. Any provision for impairment is measured based on discounted cash flows.

On a periodic basis, we evaluate our fleet of drilling rigs for marketability. During 2009 and 2008, in connection with our long term planning process, we evaluated our then-current fleet of marketable drilling rigs and identified 23 and 22 rigs, respectively, that we determined would no longer be marketed as rigs. Additionally, in 2009, we identified one rig which would be recommissioned in a different configuration. The components comprising these rigs were evaluated, and those components with continuing utility to our other marketed rigs were transferred to other rigs or to our yards to be used as spare equipment. The remaining components of these rigs were impaired and the associated net book value of $10.5 million in 2009 and $10.4 million in 2008 was expensed in our consolidated statements of operations as an impairment charge.

In late 2008, we experienced a significant decrease in the number of our rigs operating and oil and natural gas prices decreased significantly. These events were deemed by us to be triggering events that required us to perform an assessment with respect to impairment of long-lived assets, including property and equipment, in our contract drilling segment. With respect to these long-lived assets, we estimated future cash flows over the expected life of the long-lived assets, which were comprised primarily of property and equipment, and determined that, on an undiscounted basis, expected cash flows exceeded the carrying value of the long-lived assets. Based on this assessment, no impairment was indicated. We again performed an assessment with respect to impairment of long-lived assets in our contract drilling segment in 2009 based on undiscounted cash flows and determined that no impairment was indicated. Impairment considerations in our oil and natural gas segment related to proved properties are discussed below. We concluded that no triggering event had occurred with respect to our pressure pumping segment, as the level of activity and revenue impact in that segment had not been affected to the same degree as in our other segments.

Oil and natural gas properties — Working interests in oil and natural gas properties are accounted for using the successful efforts method of accounting. Under the successful efforts method of accounting, exploration costs which result in the discovery of oil and natural gas reserves and all development costs are capitalized to the appropriate well. Exploration costs which do not result in discovering oil and natural gas reserves are charged to expense when such determination is made. Costs of exploratory wells are initially capitalized to wells in progress until the outcome of the drilling is known. We review wells in progress quarterly to determine whether sufficient progress is being made in assessing the reserves and the economic operating viability of the respective projects. If no progress has been made in assessing the reserves and the economic operating viability of a project after one year following the completion of drilling, we consider the costs of the well to be impaired and recognize the costs as expense. Geological and geophysical costs, including seismic costs and costs to carry and retain undeveloped properties, are charged to expense when incurred. The capitalized costs of both developmental and successful exploratory type wells, consisting of lease and well equipment, lease acquisition costs and intangible development costs, are depreciated, depleted and amortized on the units-of-production method, based on engineering estimates of proved oil and natural gas reserves of each respective field.

We review our proved oil and natural gas properties for impairment when a triggering event occurs such as downward revisions in reserve estimates or decreases in oil and natural gas prices. Proved properties are grouped by field and undiscounted cash flow estimates are prepared based on our expectation of future commodity prices over the lives of the respective fields. These estimates are then reviewed by an independent petroleum engineer. If the net book value of a field exceeds its undiscounted cash flow estimate, impairment expense is measured and recognized as the difference between its net book value and discounted cash flow. The discounted cash flow estimates used in measuring impairment are based on our expectations of future commodity prices over the life of the respective field. Unproved oil and natural gas properties are reviewed quarterly to assess potential impairment. The intent to drill, lease expiration and abandonment of area are considered. Assessment of impairment is made on a lease-by-lease basis. If an unproved property is determined to be impaired, then costs related to that property are expensed. Impairment expense results from downward revisions in reserve estimates of proved properties and amounted to approximately $3.7 million, $4.4 million and $3.9 million for the years ended December 31, 2009, 2008 and 2007, respectively, is included in depreciation, depletion and impairment in the accompanying consolidated statements of operations.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. As such, we assess impairment of our goodwill annually as of December 31 or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. Goodwill impairment testing is performed at the level of our reporting units. Our reporting units have been determined to be the same as our operating segments.

In connection with our annual assessment of potential impairment of goodwill, we compare the fair value of the reporting unit with its carrying value. If the fair value exceeds the carrying value, no impairment is indicated. If the carrying value exceeds the fair value, we measure any impairment of goodwill in that reporting unit by allocating the fair value to the identifiable assets and liabilities of the reporting unit based on their respective fair values. Any excess unallocated fair value would equal the implied fair value of goodwill, and if that amount is below the carrying value of goodwill, an impairment charge is recognized.

In connection with our annual goodwill impairment assessment performed as of December 31, 2008, we performed an impairment test of goodwill recorded in our contract drilling and drilling and completion fluids reporting units. In light of the adverse market conditions affecting our common stock price beginning in the fourth quarter of 2008 and continuing into 2009, including a significant decrease in the number of our rigs operating and a significant decline in oil and natural gas commodity prices, we utilized a discounted cash flow methodology to estimate the fair values of our reporting units. In completing the first step of our analysis, we used a three-year projection of discounted cash flows, plus a terminal value determined using the constant growth method to estimate the fair value of our reporting units. In developing these fair value estimates, we applied key assumptions, including an assumed discount rate of 13.99% for all reporting units, an assumed long-term growth rate of 3.50% for the contract drilling reporting unit and an assumed long-term growth rate of 2.00% for the drilling and completion fluids reporting unit.

Based on the results of the first step of the impairment test in 2008, we concluded that no impairment was indicated in the contract drilling reporting unit as the estimated fair value of that reporting unit exceeded its carrying value. An impairment was indicated in our drilling and completion fluids reporting unit as the estimated fair value of that reporting unit was less than its carrying value. In validating this conclusion, we considered the results of our long-lived asset impairment tests and performed sensitivity analyses of the key assumptions used in deriving the respective fair values of our reporting units. We then performed the second step of the analysis of our drilling and completion fluids reporting unit, which included allocating the estimated fair value to the identifiable tangible and intangible assets and liabilities of this reporting unit based on their respective values. This allocation indicated no residual value for goodwill, and accordingly we recorded an impairment charge of $9.964 million in our December 31, 2008 statement of operations. We exited the drilling and completion fluids business on January 20, 2010, and the 2008 impairment charge is included in our loss from discontinued operations in our statement of operations for the year ended December 31, 2008.

We again performed our annual goodwill impairment assessment as of December 31, 2009 related to the remaining $86.2 million in goodwill recorded in our contract drilling reporting unit. In completing the first step of our analysis, we used a three-year projection of discounted cash flows, plus a terminal value determined using the constant growth method to estimate the fair value of our reporting unit. In developing this fair value estimate, we applied key assumptions, including an assumed discount rate of 15.42% and an assumed long-term growth rate of 3.50%. Based on the results of the first step of the impairment test in 2009, we concluded that no impairment was indicated in our contract drilling reporting unit as the estimated fair value of that reporting unit exceeded its carrying value.

In the event that market conditions weaken, we may be required to record an impairment of goodwill in our contract drilling reporting unit in the future, and such impairment could be material.

Revenue recognition — Revenues are recognized when services are performed, except for revenues earned under turnkey contract drilling arrangements which are recognized using the completed contract method of accounting. We follow the percentage-of-completion method of accounting for footage contract drilling arrangements. Under the percentage-of-completion method, management estimates are relied upon in the determination of the total estimated expenses to be incurred drilling the well. Due to the nature of turnkey contract drilling arrangements and risks therein, we follow the completed contract method of accounting for such arrangements. Under this method, revenues and expenses related to a well in progress are deferred and recognized in the period the well is completed. Provisions for losses on incomplete or in-process wells are made when estimated total expenses are expected to exceed total revenues. We recognize reimbursements received from third parties for out-of-pocket expenses incurred as revenues and account for these out-of-pocket expenses as direct costs. Except for two wells drilled under footage contacts in 2009, all of the wells we drilled in 2009, 2008 and 2007 were drilled under daywork contracts.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from such estimates.

Key estimates used by management include:

- allowance for doubtful accounts,
- depreciation and depletion,
- goodwill and long-lived asset impairments, and
- reserves for self-insured levels of insurance coverage.

For additional information on our accounting policies, see Note 1 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report.

Liquidity and Capital Resources

As of December 31, 2009, we had working capital of $264 million, including cash and cash equivalents of $49.9 million. During 2009, our sources of cash flow included:

- $454 million from operating activities,
- $3.4 million in proceeds from the disposal of property and equipment, and

During 2009, we used $30.7 million to pay dividends on our common stock, $6.2 million to pay issuance costs related to our revolving credit facility, $1.6 million to repurchase shares of our common stock and $453 million:

- to build new drilling rigs,
- to make capital expenditures for the betterment and refurbishment of our drilling rigs,
- to acquire and procure drilling equipment and facilities to support our drilling operations,
- to fund capital expenditures for our pressure pumping segment, and
- to fund investments in oil and natural gas properties on a working interest basis.

We paid cash dividends during the year ended December 31, 2009 as follows:

	Per Share	Total (In thousands)
Paid on March 31, 2009	$0.05	$ 7,655
Paid on June 30, 2009	0.05	7,675
Paid on September 30, 2009	0.05	7,675
Paid on December 30, 2009	0.05	7,676
Total cash dividends	$0.20	$30,681

On February 10, 2010, our Board of Directors approved a cash dividend on our common stock in the amount of $0.05 per share to be paid on March 30, 2010 to holders of record as of March 15, 2010. The amount and timing of all future dividend payments, if any, is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of our credit facilities and other factors.

On August 1, 2007, our Board of Directors approved a stock buyback program ("Program"), authorizing purchases of up to $250 million of our common stock in open market or privately negotiated transactions. During the year ended December 31, 2009, we purchased 5,715 shares of our common stock under the Program at a cost of approximately $79,000. As of December 31, 2009, we are authorized to purchase approximately $113 million of our outstanding common stock under the Program.

We have an unsecured revolving credit facility with a maximum borrowing and letter of credit capacity of $240 million. Interest is paid on the outstanding principal amount of borrowings under the revolving credit facility at a floating rate based on, at our election, LIBOR or a base rate. The margin on LIBOR loans ranges from 3.00% to

4.00% and the margin on base rate loans ranges from 2.00% to 3.00%, based on our debt to capitalization ratio. Any outstanding borrowings must be repaid at maturity on January 31, 2012 and letters of credit may remain in effect up to six months after such maturity date. As of December 31, 2009, we had no borrowings outstanding under the revolving credit facility. We had $46.3 million in letters of credit outstanding at December 31, 2009, and as a result, had available borrowing capacity of approximately $194 million at such date.

There are customary representations, warranties, restrictions and covenants associated with the revolving credit facility. Financial covenants provide for a maximum debt to capitalization ratio and a minimum interest coverage ratio. As of December 31, 2009, the maximum debt to capitalization ratio was 35% and the minimum interest coverage ratio was 3.00 to 1. We were in compliance with these financial covenants as of December 31, 2009. We do not expect that the restrictions and covenants will impact our ability to operate or react to opportunities that might arise.

We believe that the current level of cash, short-term investments and borrowing capacity available under our revolving credit facility, together with cash expected to be generated from operations (including expected income tax refunds in 2010 of approximately $114 million resulting from the carry-back of net operating losses), should be sufficient to meet our current capital needs. From time to time, opportunities to expand our business, including acquisitions and the building of new rigs are evaluated. The timing, size or success of any acquisition and the associated capital commitments are unpredictable. If we pursue opportunities for growth that require capital, we believe we would be able to satisfy these needs through a combination of working capital, cash generated from operations, borrowing capacity under our revolving credit facility or additional debt or equity financing. However, there can be no assurance that such capital will be available on reasonable terms, if at all.

Contractual Obligations

The following table presents information with respect to our contractual obligations as of December 31, 2009 (dollars in thousands):

	Payments due by period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Borrowings under revolving credit facility(1)	$ —	$ —	$—	$—	$—
Commitments to purchase equipment(2)	186,220	186,220	—	—	—
	$186,220	$186,220	$—	$—	$—

(1) No borrowings were outstanding on our revolving credit facility as of December 31, 2009. Our revolving credit facility matures on January 31, 2012.

(2) Represents commitments to purchase major equipment to be delivered in 2010 based on expected delivery dates.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements at December 31, 2009.

Results of Operations

Comparison of the years ended December 31, 2009 and 2008

The following tables summarize operations by business segment for the years ended December 31, 2009 and 2008:

Contract Drilling	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands)		
Revenues	$599,287	$1,804,026	(66.8)%
Direct operating costs	$357,742	$1,038,327	(65.5)%
Selling, general and administrative	$ 4,340	$ 5,363	(19.1)%
Depreciation and impairment	$248,424	$ 239,700	3.6%
Operating income (loss)	$(11,219)	$ 520,636	N/A%
Operating days	33,394	93,068	(64.1)%
Average revenue per operating day	$ 17.95	$ 19.38	(7.4)%
Average direct operating costs per operating day	$ 10.71	$ 11.16	(4.0)%
Average rigs operating	91	254	(64.2)%
Capital expenditures	$395,376	$ 360,645	9.6%

The demand for our contract drilling services is impacted by the market price of natural gas and, to a lesser extent, oil. The reactivation and construction of new land drilling rigs in the United States in recent years has also contributed to an excess capacity of land drilling rigs compared to demand. The average market price of natural gas for each of the fiscal quarters and full years in 2009 and 2008 follow:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2008:					
Average natural gas price(1)	$8.92	$11.74	$9.28	$6.60	$9.13
2009:					
Average natural gas price(1)	$4.71	$ 3.82	$3.26	$4.46	$4.06

(1) The average natural gas price represents the Henry Hub Spot price as reported by the United States Energy Information Administration.

Revenues and direct operating costs decreased in 2009 compared to 2008 primarily as a result of a decrease in the number of operating days. The decrease in operating days was due to decreased demand largely caused by lower commodity prices for natural gas and oil. Our average number of rigs operating during 2009 included an average of approximately six rigs under term contracts that earned standby revenues of $22.3 million. This represented an increase from an average of approximately one rig under term contract that earned standby revenues of $4.7 million in 2008. Rigs on standby earn a discounted dayrate as they do not have crews and have lower costs. We recognized approximately $8.0 million of revenues during 2009 from the early termination of drilling contracts compared to approximately $1.3 million in 2008. Average revenue per operating day decreased in 2009 primarily due to decreases in dayrates for rigs that were operating in the spot market and the expiration of term contracts that were entered into at higher rates. Average direct operating costs per operating day decreased in 2009 primarily due to decreases in labor and repair costs. Significant capital expenditures were incurred in 2009 and 2008 to build new drilling rigs, to modify and upgrade our drilling rigs and to acquire additional related equipment such as drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment. Depreciation and impairment expense includes approximately $10.5 million in 2009 and approximately $10.4 million in 2008 related to the impairment of drilling equipment primarily related to drilling rigs that were removed from our marketable fleet. We removed 23 rigs from our marketable fleet in 2009 and removed 22 rigs from our marketable fleet in 2008. Depreciation expense increased as a result of capital expenditures.

Pressure Pumping	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands)		
Revenues	$161,441	$217,494	(25.8)%
Direct operating costs	$111,414	$132,570	(16.0)%
Selling, general and administrative	$ 21,421	$ 23,305	(8.1)%
Depreciation	$ 27,589	$ 19,600	40.8%
Operating income	$ 1,017	$ 42,019	(97.6)%
Total jobs	7,265	12,900	(43.7)%
Average revenue per job	$ 22.22	$ 16.86	31.8%
Average direct operating costs per job	$ 15.34	$ 10.28	49.2%
Capital expenditures	$ 43,144	$ 61,289	(29.6)%

Our customers have increased their focus on the emerging development of unconventional reservoirs in the Appalachian Basin and the larger jobs associated therewith. As a result of this focus on unconventional reservoirs and lower commodity prices, we experienced a decrease in smaller traditional pressure pumping jobs, which contributed to the overall decrease in the number of total jobs. Revenues and direct operating costs decreased as a result of the decrease in the number of total jobs. Increased average revenue per job reflects an increase in the proportion of larger jobs to total jobs, which was driven by demand for services associated with unconventional reservoirs, partially offset by the impact of reduced pricing. Average direct operating costs per job increased due to the increase in larger jobs and as a result of fixed costs being spread over a significantly reduced number of total jobs. In anticipation of increased activity associated with the unconventional reservoirs in the Appalachian Basin, we have added facilities, equipment and personnel in recent years. Delays in the development of these reservoirs and lower commodity prices have caused a slower increase in customer activity than we had expected, negatively impacting the profitability of this business. Selling, general and administrative expenses decreased primarily as a result of cost containment efforts during the downturn in the industry. Significant capital expenditures have been incurred in recent years to add capacity. Depreciation expense increased as a result of capital expenditures.

Oil and Natural Gas Production and Exploration	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands, except commodity prices)		
Revenues	$21,218	$42,360	(49.9)%
Direct operating costs	$ 7,341	$12,793	(42.6)%
Depreciation, depletion and impairment	$12,927	$15,856	(18.5)%
Operating income	$ 950	$13,711	(93.1)%
Capital expenditures	$ 7,341	$22,981	(68.1)%
Average net daily oil production (Bbls)	761	801	(5.0)%
Average net daily gas production (Mcf)	3,225	3,755	(14.1)%
Average oil sales price (per Bbl)	$ 58.09	$ 98.70	(41.1)%
Average gas sales price (per Mcf)	$ 4.32	$ 9.77	(55.8)%

Revenues decreased due to lower average sales prices and lower average net daily production of oil and natural gas. Average net daily oil and natural gas production decreased primarily due to production declines on existing wells. Direct operating costs decreased primarily due to decreases in seismic expenses as well as decreased production taxes and other production costs. Depreciation, depletion and impairment expense in 2009 includes approximately $3.7 million incurred to impair certain oil and natural gas properties compared to approximately $4.4 million incurred to impair certain oil and natural gas properties in 2008. Depletion expense decreased approximately $2.3 million primarily due to lower production and the impact of decreases in the carrying value of properties resulting from previous impairment charges. Capital expenditures decreased in 2009 as a result of declines in commodity prices.

Corporate and Other	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands)		
Selling, general and administrative	$30,860	$29,412	4.9%
Depreciation	$ 907	$ 834	8.8%
Other operating expenses	$ 3,810	$ 4,350	(12.4)%
Net (gain) loss on asset disposals	$ 3,385	$ (4,163)	N/A%
Interest income	$ 381	$ 1,553	(75.5)%
Interest expense	$ 4,148	$ 630	558.4%
Other income	$ 426	$ 502	(15.1)%
Capital expenditures	$ 6,785	$ 511	1,227.8%

Selling, general and administrative expense increased in 2009 primarily as a result of increased professional fees. Other operating expenses decreased due to a decrease in bad debt expense. Gains and losses on the disposal of assets are treated as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. Losses on asset disposals in 2009 were primarily related to the disposal of contract drilling equipment. Gains on asset disposals in 2008 were primarily related to gains on the sale of contract drilling equipment and the sale of oil and natural gas properties. Interest expense increased in 2009 due to the amortization of revolving credit facility issuance costs and increased fees associated with outstanding letters of credit and the unused portion of the revolving credit facility. Capital expenditures increased in 2009 due to the purchase and ongoing implementation of a new enterprise resource planning system.

Discontinued Operations:	Year Ended December 31, 2009	2008	% Change
	(Dollars in thousands)		
Drilling and completion fluids revenue	$79,786	$145,246	(45.1)%
Drilling and completion fluids direct operating costs	$74,180	$126,900	(41.5)%
Drilling and completion fluids selling, general and administrative	$ 7,192	$ 10,110	(28.9)%
Drilling and completion fluids depreciation	$ 2,287	$ 2,830	(29.2)%
Goodwill impairment	$ —	$ 9,964	(100.0)%
Impairment of assets held for sale	$ 1,900	$ —	N/A%
Net gain on asset disposals/retirements	$ (125)	$ (155)	(19.4)%
Other operating expense	$ 890	$ —	N/A%
Net interest expense	$ —	$ 7	(100.0)%
Income tax expense (benefit)	$ (2,208)	$ 2,389	N/A%
Loss from discontinued operations, net of income taxes	$ (4,330)	$ (6,799)	36.3%

On January 20, 2010, we exited our drilling and completion fluids services business which had previously been presented as one of our reportable operating segments. On that date, our wholly owned subsidiary, Ambar Lone Star Fluids Services LLC, completed the sale of substantially all of its assets, excluding billed accounts receivable. Upon our exit from this business, we classified our drilling and completion fluids operating segment as a discontinued operation. Accordingly, the assets and liabilities of this business, along with its results of operations, have been reclassified for all periods presented. Drilling and completion fluids revenue and direct operating costs decreased in 2009 due to decreased sales volume both on land and offshore in the Gulf of Mexico. Drilling and completion fluids selling, general and administrative expenses decreased in 2009 primarily due to a decrease in compensation costs for sales and support personnel due to headcount reductions. Goodwill impairment was recognized in the drilling and completion fluids reporting unit in 2008 as a result of our annual impairment testing which indicated that the fair value of goodwill in that reporting unit was zero. Impairment of assets held for sale in 2009 of $1.9 million represents the adjustment recorded to reduce the carrying value of the assets sold to their fair value less transaction costs as of December 31, 2009. In 2008, income tax expense was recognized despite a pre-tax loss in the drilling and completion fluids business due to the fact that the goodwill impairment recorded in that year was not deductible for tax purposes.

Comparison of the years ended December 31, 2008 and 2007

The following tables summarize operations by business segment for the years ended December 31, 2008 and 2007:

Contract Drilling	Year Ended December 31, 2008	2007	% Change
	(Dollars in thousands)		
Revenues	$1,804,026	$1,741,647	3.6%
Direct operating costs	$1,038,327	$ 963,150	7.8%
Selling, general and administrative	$ 5,363	$ 5,893	(9.0)%
Depreciation and impairment	$ 239,700	$ 213,812	12.1%
Operating income	$ 520,636	$ 558,792	(6.8)%
Operating days	93,068	89,095	4.5%
Average revenue per operating day	$ 19.38	$ 19.55	(0.9)%
Average direct operating costs per operating day	$ 11.16	$ 10.81	3.2%
Average rigs operating	254	244	4.1%
Capital expenditures	$ 360,645	$ 539,506	(33.2)%

The demand for our contract drilling services is impacted by the market price of natural gas and, to a lesser extent, oil. The reactivation and construction of new land drilling rigs in the United States in recent years has also contributed to an excess capacity of land drilling rigs compared to demand. The average market price of natural gas for each of the fiscal quarters and full years in 2008 and 2007 follow:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year
2007:					
Average natural gas price(1)	$7.44	$ 7.76	$6.35	$7.19	$7.18
2008:					
Average natural gas price(1)	$8.92	$11.74	$9.28	$6.60	$9.13

(1) The average natural gas price represents the Henry Hub Spot price as reported by the United States Energy Information Administration.

Revenues and direct operating costs increased in 2008 compared to 2007 primarily as a result of an increase in the number of operating days. The increase in operating days was due to increased demand caused by higher prices for natural gas during most of 2008 compared to 2007. Average revenue per operating day in 2008 was relatively flat compared to 2007. Average direct operating costs per operating day increased in 2008 due to incremental costs incurred to activate idle drilling rigs as well as increases in labor, repairs and other related costs. Significant capital expenditures were incurred in 2008 and 2007 to build new drilling rigs, to modify and upgrade our drilling rigs and to acquire additional related equipment such as drill pipe, drill collars, engines, fluid circulating systems, rig hoisting systems and safety enhancement equipment. Depreciation and impairment expense in 2008 includes approximately $10.4 million related to the impairment of drilling equipment primarily related to drilling rigs that were removed from our marketable fleet. We removed 22 rigs from our marketable fleet in 2008. Depreciation expense increased as a result of capital expenditures.

Pressure Pumping	Year Ended December 31, 2008	2007	% Change
	(Dollars in thousands)		
Revenues	$217,494	$202,812	7.2%
Direct operating costs	$132,570	$105,273	25.9%
Selling, general and administrative	$ 23,305	$ 18,971	22.8%
Depreciation	$ 19,600	$ 14,311	37.0%
Operating income	$ 42,019	$ 64,257	(34.6)%
Total jobs	12,900	14,094	(8.5)%
Average revenue per job	$ 16.86	$ 14.39	17.2%
Average direct operating costs per job	$ 10.28	$ 7.47	37.6%
Capital expenditures	$ 61,289	$ 47,582	28.8%

Our customers increased their focus on the emerging development of unconventional reservoirs in the Appalachian Basin and the larger jobs associated therewith. As a result of this focus on unconventional reservoirs, we experienced a decrease in smaller traditional pressure pumping jobs in 2008, which resulted in an overall decrease in the number of total jobs. Revenues and direct operating costs increased as a result of an increase in the average revenue and average direct operating costs per job. Increased average revenue per job was due to an increase in the proportion of larger jobs to total jobs, which was driven by demand for services associated with unconventional reservoirs. Average direct operating costs per job increased due to the increase in larger jobs and as a result of increases in compensation, maintenance and the cost of materials used in our operations. In anticipation of increased activity associated with the unconventional reservoirs in the Appalachian Basin, we added facilities, equipment and personnel. Delays in the development of these reservoirs caused a slower increase in customer activity than we had expected, negatively impacting the profitability of this business. Selling, general and administrative expense increased primarily as a result of expenses to support expanded operations of this segment. Significant capital expenditures were incurred to add capacity, expand our areas of operation and modify and upgrade existing equipment. Depreciation expense increased as a result of capital expenditures.

Oil and Natural Gas Production and Exploration	Year Ended December 31, 2008	2007	% Change
	(Dollars in thousands, except commodity prices)		
Revenues	$42,360	$41,637	1.7%
Direct operating costs	$12,793	$10,864	17.8%
Selling, general and administrative	$ —	$ 2,365	(100.0)%
Depreciation, depletion and impairment	$15,856	$17,410	(8.9)%
Operating income	$13,711	$10,998	24.7%
Capital expenditures	$22,981	$17,516	31.2%
Average net daily oil production (Bbls)	801	971	(17.5)%
Average net daily gas production (Mcf)	3,755	4,996	(24.8)%
Average oil sales price (per Bbl)	$ 98.70	$ 68.82	43.4%
Average gas sales price (per Mcf)	$ 9.77	$ 7.37	32.6%

Revenues increased due to higher average sales prices of oil and natural gas. This increase was partially offset by a decrease in the average net daily production of oil and natural gas and by the elimination of well operations revenue due to the fourth quarter 2007 sale of the operating responsibilities associated with oil and natural gas wells. Average net daily oil and natural gas production decreased primarily due to the sale of properties in 2007 and production declines. Direct operating costs increased due to an increase in seismic expenses as well as increased production taxes and other production costs. Selling, general and administrative expense decreased in 2008 due to the sale of the operating responsibilities mentioned above and the resulting elimination of headcount in this segment. Depreciation, depletion and impairment expense in 2008 includes approximately $4.4 million incurred to impair certain oil and natural gas properties compared to approximately $3.9 million incurred to impair certain oil and natural gas properties in 2007. Depletion expense decreased approximately $1.9 million primarily due to the sale of certain properties in 2007.

Corporate and Other	Year Ended December 31, 2008	2007	% Change
	(Dollars in thousands)		
Selling, general and administrative	$29,412	$ 27,436	7.2%
Depreciation	$ 834	$ 813	2.6%
Other operating expenses	$ 4,350	$ 2,875	51.3%
Embezzlement recoveries	$ —	$(43,955)	(100.0)%
Net gain on asset disposals	$ (4,163)	$(16,432)	(74.7)%
Interest income	$ 1,553	$ 2,351	(33.9)%
Interest expense	$ 630	$ 2,187	(71.2)%
Other income	$ 502	$ 363	38.3%
Capital expenditures	$ 511	$ —	N/A%

Selling, general and administrative expense increased primarily as a result of additional compensation expense and an increase in payroll tax expense associated with the exercise of stock options during 2008. Other operating expenses increased due to an increase in bad debt expense. Gains and losses on the disposal of assets are considered as part of our corporate activities because such transactions relate to corporate strategy decisions of our executive management group. Gains on asset disposals in 2008 were primarily related to gains on the sale of contract drilling equipment and the sale of oil and natural gas properties. Gains on asset disposals in 2007 were primarily related to the sale of oil and natural gas properties.

In November 2005, we discovered that our former Chief Financial Officer, Jonathan D. Nelson ("Nelson"), had fraudulently diverted approximately $77.5 million in Company funds for his own benefit during the period from 1998 through 2005. As a result, the Audit Committee of the Board of Directors commenced an investigation into Nelson's activities and retained independent counsel and independent forensic accountants to assist with the investigation. Nelson has been sentenced and is serving a term of imprisonment arising out of his embezzlement. A receiver was appointed to take control of and liquidate the assets of Nelson. In May 2007, the court approved a plan of distribution for the assets recovered by the receiver. We recovered a total of approximately $44.5 million pursuant to the approved plan, and we recognized this recovery in our consolidated statement of income in 2007, net of professional fees incurred as a result of the embezzlement.

Discontinued Operations:	Year Ended December 31, 2008	2007	% Change
	(Dollars in thousands)		
Drilling and completion fluids revenue	$145,246	$128,098	13.4%
Drilling and completion fluids direct operating costs	$126,900	$108,752	16.7%
Drilling and completion fluids selling, general and administrative	$ 10,110	$ 9,958	1.5%
Drilling and completion fluids depreciation	$ 2,830	$ 2,860	(1.0)%
Goodwill impairment	$ 9,964	$ —	N/A%
Net gain on asset disposals/retirements	$ (155)	$ (113)	37.2%
Other operating benefit	$ —	$ (325)	(100.0)%
Net interest expense (income)	$ 7	$ (4)	N/A%
Income tax expense	$ 2,389	$ 2,818	(15.2)%
Income (loss) from discontinued operations, net of income taxes	$ (6,799)	$ 4,152	N/A%

Drilling and completion fluids revenue and direct operating costs increased in 2008 due to increased sales volume both on land and offshore in the Gulf of Mexico. Goodwill impairment was recognized in the drilling and completion fluids reporting unit in 2008 as a result of our annual impairment testing which indicated that the fair value of goodwill in that reporting unit was zero. No impairment of goodwill was recognized in 2007 as the annual impairment testing did not indicate that an impairment existed at that time. In 2008, income tax expense was recognized despite a pre-tax loss in the drilling and completion fluids business due to the fact that the goodwill impairment recorded in that year was not deductible for tax purposes.

Income Taxes

	Year Ended December 31,		
	2009	2008	2007
	(Dollars in thousands)		
Income (loss) from continuing operations before income tax	$(51,555)	$547,358	$663,837
Income tax expense (benefit)	(17,595)	193,490	229,350
Effective tax rate	34.1%	35.3%	34.5%

The effective tax rate is a result of a Federal rate of 35.0% adjusted as follows:

	2009	2008	2007
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	4.7	1.7	1.4
Permanent differences	(5.7)	(1.2)	(1.6)
Other, net	0.1	(0.2)	(0.3)
Effective tax rate	34.1%	35.3%	34.5%

The permanent differences indicated above are largely attributable to our Domestic Production Activities deduction. The Domestic Production Activities Deduction was enacted as part of the American Jobs Creation Act of 2004 (as revised by the Emergency Economic Stabilization Act of 2008, the "Act") and is effective for taxable years after December 31, 2004. The Act allows a deduction of 6% on the lesser of qualified production activities income or taxable income.

We record deferred Federal income taxes based primarily on the temporary differences between the book and tax bases of our assets. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be settled. As a result of fully recognizing the benefit of our deferred income taxes, we incur deferred income tax expense as these benefits are utilized. We recognized deferred tax expense of approximately $101 million in 2009, $65.4 million in 2008 and $38.3 million in 2007.

Volatility of Oil and Natural Gas Prices and its Impact on Operations and Financial Condition

Our revenue, profitability, financial condition and rate of growth are substantially dependent upon prevailing prices for natural gas and, to a lesser extent, oil. For many years, oil and natural gas prices and markets have been extremely volatile. Prices are affected by market supply and demand factors as well as international military, political and economic conditions, and the ability of OPEC to set and maintain production and price targets. All of these factors are beyond our control. During 2008, the monthly average market price of natural gas (monthly average Henry Hub price as reported by the Energy Information Administration) peaked in June at $13.06 per Mcf before rapidly declining to an average of $5.99 per Mcf in December. In 2009, the monthly average market price of natural gas declined further to a low of $3.06 per Mcf in September. This decline in the market price of natural gas resulted in our customers significantly reducing their drilling activities beginning in the fourth quarter of 2008 and drilling activities remained low throughout 2009. This reduction in demand combined with the reactivation and construction of new land drilling rigs in the United States during the last several years has resulted in excess capacity compared to demand. As a result of these factors, our average number of rigs operating has declined significantly. We expect oil and natural gas prices to continue to be volatile and to affect our financial condition, operations and ability to access sources of capital. Low market prices for natural gas would likely result in demand for our drilling rigs remaining low and adversely affect our operating results, financial condition and cash flows.

The North American land drilling industry has experienced downturns in demand during the last decade. During these periods, there have been substantially more drilling rigs available than necessary to meet demand. As a result, drilling contractors have had difficulty sustaining profit margins and, at times, have incurred losses during the downturn periods.

Impact of Inflation

Inflation has not had a significant impact on our operations during the three years in the period ended December 31, 2009. We believe that inflation will not have a significant near-term impact on our financial position.

Recently Issued Accounting Standards

In June 2008, the FASB issued a new accounting standard which clarifies that share-based payment awards that entitle their holders to receive non-forfeitable dividends before vesting should be considered participating securities and, as such, should be included in the calculation of basic earnings-per-share using the two-class method. Certain of our share-based payment awards entitle the holders to receive non-forfeitable dividends. This standard is effective for financial statements issued for fiscal years beginning after December 15, 2008, as well as interim periods within those years and became effective for us on January 1, 2009. The impact of the adoption of this standard is discussed in Note 1 of our Consolidated Financial Statements.

In December 2008, the SEC issued a Final Rule, *Modernization of Oil and Gas Reporting* ("Final Rule"). The Final Rule revises certain oil and gas reporting disclosures in Regulation S-K and Regulation S-X under the Securities Act, and the Exchange Act, as well as Industry Guide 2. The amendments are designed to modernize and update oil and gas disclosure requirements to align them with current practices and changes in technology. The disclosure requirements are effective for registration statements filed on or after January 1, 2010 and for annual financial statements filed on or after December 31, 2009. We applied the provisions of the Final Rule in connection with our December 31, 2009 oil and natural gas reserve estimation process. The application of the Final Rule did not have a material impact on us.

In April 2009, the FASB issued a staff position to provide additional guidance for determining whether a market for a financial asset is not active and a transaction is not distressed for fair value measurements under generally accepted accounting principles. The provisions of this staff position are effective for financial statements issued for interim and annual periods ending after June 15, 2009 and became effective for us in the quarter ended June 30, 2009. The adoption of this staff position did not have a material impact on us.

In April 2009, the FASB issued a staff position which increases the frequency of fair value disclosures for financial instruments from annual only to quarterly reporting periods. The provisions of this staff position are effective for financial statements issued for interim and annual periods ending after June 15, 2009 and became effective for us in the quarter ended June 30, 2009. The adoption of this staff position did not have a material impact on us.

In June 2009, the FASB issued a new accounting standard that amends the accounting and disclosure requirements for the consolidation of variable interest entities. This new standard removes the previously existing exception from applying consolidation guidance to qualifying special-purpose entities and requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. Before this new standard, generally accepted accounting principles required reconsideration of whether an enterprise is the primary beneficiary of a variable interest entity only when specific events occurred. This new standard is effective as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. This new standard became effective for us on January 1, 2010. The adoption of this standard did not impact our consolidated financial statements.

In June 2009, the FASB issued the FASB Accounting Standards Codification ("Codification"). Effective for financial statements issued for interim and annual periods ending after September 15, 2009, the Codification became the source of authoritative U.S. generally accepted accounting principles. The FASB will no longer issue new standards in the form of Statements, FASB Staff Positions or EITF Abstracts. Instead, it will issue Accounting Standards Updates to update the Codification. The adoption of the Codification did not impact our consolidated financial statements.

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

We currently have exposure to interest rate market risk associated with any borrowings that we have under our revolving credit facility. The revolving credit facility calls for periodic interest payments at a floating rate ranging from LIBOR plus 3.00% to 4.00% or at the prime rate. The applicable rate above LIBOR is based upon our debt to capitalization ratio. As of December 31, 2009, we had no borrowings outstanding under our revolving credit facility.

We conduct a portion of our business in Canadian dollars through our Canadian land-based drilling operations. The exchange rate between Canadian dollars and U.S. dollars has fluctuated during the last several years. If the value of the Canadian dollar against the U.S. dollar weakens, revenues and earnings of our Canadian operations will be reduced and the value of our Canadian net assets will decline when they are translated to U.S. dollars.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items.

Item 8. *Financial Statements and Supplementary Data.*

Financial Statements are filed as a part of this Report at the end of Part IV hereof beginning at page F-1, Index to Consolidated Financial Statements, and are incorporated herein by this reference.

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

None.

Item 9A. *Controls and Procedures.*

Disclosure Controls and Procedures:

Under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Exchange Act, as of the end of the period covered by this Report. Based on this evaluation, our CEO and CFO concluded that, as of December 31, 2009, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and is accumulated and reported to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

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 Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our CEO and CFO, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2009, based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our management has concluded that our internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-2 of this Report and is incorporated by reference into Item 8 of this Report.

Changes in Internal Control over Financial Reporting:

There have been no changes in our internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

None.

PART III

The information required by Part III is omitted from this Report because we expect to file a definitive proxy statement (the "Proxy Statement") pursuant to Regulation 14A of the Securities Exchange Act of 1934 no later than 120 days after the end of the fiscal year covered by this Report and certain information included therein is incorporated herein by reference.

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

The information required by this Item is incorporated herein by reference to the Proxy Statement.

We have adopted a Code of Business Conduct and Ethics for Senior Financial Executives, which covers, among others, our principal executive officer, principal financial officer and principal accounting officer. The text of this code is located on our website under "Governance." Our Internet address is www.patenergy.com. We intend to disclose any amendments to or waivers from this code on our website.

Item 11. *Executive Compensation.*

The information required by this Item is incorporated herein by reference to the Proxy Statement.

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

The information required by this Item is incorporated herein by reference to the Proxy Statement.

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

The information required by this Item is incorporated herein by reference to the Proxy Statement.

Item 14. *Principal Accountant Fees and Services.*

The information required by this Item is incorporated herein by reference to the Proxy Statement.

PART IV

Item 15. ***Exhibits and Financial Statement Schedule.***

(a)(1) *Financial Statements*

See Index to Consolidated Financial Statements on page F-1 of this Report.

(a)(2) *Financial Statement Schedule*

Schedule II — Valuation and qualifying accounts is filed herewith on page S-1.

All other financial statement schedules have been omitted because they are not applicable or the information required therein is included elsewhere in the financial statements or notes thereto.

(a)(3) *Exhibits*

The following exhibits are filed herewith or incorporated by reference herein.

3.1	Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.2	Amendment to Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).
3.3	Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 and incorporated herein by reference).
4.1	Rights Agreement dated January 2, 1997, between Patterson Energy, Inc. and Continental Stock Transfer & Trust Company (filed January 14, 1997 as Exhibit 2 to the Company's Registration Statement on Form 8-A and incorporated herein by reference).
4.2	Amendment to Rights Agreement dated as of October 23, 2001 (filed October 31, 2001 as Exhibit 3.4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2001 and incorporated herein by reference).
4.3	Restated Certificate of Incorporation, as amended (See Exhibits 3.1 and 3.2).
4.4	Registration Rights Agreement with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned by REMY Capital Partners III, L.P. (filed March 19, 2002 as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).
10.1	For additional material contracts, see Exhibits 4.1, 4.2 and 4.4.
10.2	Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan (filed November 27, 2002 as Exhibit 4.4 to Post Effective Amendment No. 1 to the Company's Registration Statement on Form S-8 (File No. 333-60470) and incorporated herein by reference).*
10.3	Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan (filed July 28, 2003 as Exhibit 4.7 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 and incorporated herein by reference).*
10.4	Amendment to the Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan (filed August 9, 2004 as Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*
10.5	Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan (filed July 25, 2001 as Exhibit 4.4 to Post-Effective Amendment No. 1 to the Company's Registration Statement on Form S-8 (File No. 333-60466) and incorporated herein by reference).*
10.6	Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, including Form of Executive Officer Restricted Stock Award Agreement, Form of Executive Officer Stock Option Agreement, Form of Non-Employee Director Restricted Stock Award Agreement and Form of Non-Employee Director Stock Option Agreement (filed June 21, 2005 as Exhibit 10.1 to the Company's Current Report on Form 8-K, and incorporated herein by reference).*
10.7	First Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.8 Second Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.9 Form of Cash-Settled Performance Unit Award Agreement pursuant to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended from time to time.*

10.10 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Mark S. Siegel (filed on February 4, 2004 as Exhibit 10.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.11 Employment Agreement, dated as of September 1, 2007 between Patterson-UTI Energy, Inc. and Cloyce A. Talbott (filed on September 24, 2007 as Exhibit 10.1 to the Company's Current Report on Form 8-K, and incorporated herein by reference).*

10.12 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Kenneth N. Berns (filed on February 4, 2004 as Exhibit 10.5 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.13 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed on February 4, 2004 as Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.14 Form of Letter Agreement regarding termination, effective as of January 29, 2004, entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns and John E. Vollmer III (filed on February 25, 2005 as Exhibit 10.23 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference).*

10.15 Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Cloyce A. Talbott, Douglas J. Wall, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Kenneth R. Peak, Charles O. Buckner, John E. Vollmer III, Seth D. Wexler and Gregory W. Pipkin (filed April 28, 2004 as Exhibit 10.11 to the Company's Annual Report on Form 10-K, as amended, for the year ended December 31, 2003 and incorporated herein by reference).*

10.16 Severance Agreement between Patterson-UTI Energy, Inc. and Douglas J. Wall, effective as of August 31, 2007 (filed September 4, 2007 as Exhibit 10.3 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.17 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of August 31, 2007, by and between Patterson-UTI Energy, Inc. and Douglas J. Wall (filed September 4, 2007 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.18 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of November 2, 2009, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler (filed November 2, 2009 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009 and incorporated herein by reference).*

10.19 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Mark S. Siegel, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.20 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Douglas J. Wall, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.21 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and John E. Vollmer, III, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.22 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Kenneth N. Berns, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.23 Credit Agreement dated March 20, 2009, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, each of Amegy Bank, N.A., Comerica Bank, and HSBC Bank USA, N.A., as lender, Bank of America, N.A., as syndication agent, letter of credit issuer and lender, and The Bank of Tokyo-Mitsubishi UFJ, Ltd. as documentation agent and lender (filed March 25, 2009 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.24 Commitment Increase and Joinder Agreement dated June 19, 2009, among the Company, as borrower, Regions Bank as the new lender, Bank of America, N.A., as a letter of credit issuer and Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender (filed August 4, 2009 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference).

10.25 Letter Agreement dated February 6, 2006 between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed May 1, 2006 as Exhibit 10.25 to the Company's Annual Report on Form 10-K, as amended, and incorporated herein by reference).*

21.1 Subsidiaries of the Registrant.

23.1 Consent of Independent Registered Public Accounting Firm.

31.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.

31.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.

32.1 Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101 The following materials from Patterson-UTI Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2009, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Stockholders' Equity, (iv) the Consolidated Statements of Cash Flows, (v) Notes to Consolidated Financial Statements, tagged as blocks of text, and (vi) Valuation and Qualifying Accounts.

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* Management Contract or Compensatory Plan identified as required by Item 15(a)(3) of Form 10-K.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders
of Patterson-UTI Energy, Inc.:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Patterson-UTI Energy, Inc. and its subsidiaries (the "Company") at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) 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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 19, 2010

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 49,877	$ 81,223
Accounts receivable, net of allowance for doubtful accounts of $10,911 and $9,330 at December 31, 2009 and 2008, respectively	164,498	414,531
Federal and state income taxes receivable	118,869	10,175
Inventory	6,941	41,999
Deferred tax assets, net	32,877	35,928
Assets held for sale	42,424	—
Other	41,782	57,518
Total current assets	457,268	641,374
Property and equipment, net	2,110,402	1,937,112
Goodwill	86,234	86,234
Deposits on equipment purchases	914	43,944
Other	7,334	4,153
Total assets	$2,662,152	$2,712,817
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 83,700	$ 169,958
Accrued expenses	109,608	132,655
Total current liabilities	193,308	302,613
Borrowings under revolving credit facility	—	—
Deferred tax liabilities, net	381,656	277,717
Other	5,488	5,545
Total liabilities	580,452	585,875
Commitments and contingencies (see Note 9)	—	—
Stockholders' equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $.01; authorized 300,000,000 shares with 180,828,773 and 180,192,093 issued and 153,610,785 and 153,094,803 outstanding at December 31, 2009 and 2008, respectively	1,808	1,801
Additional paid-in capital	781,635	765,512
Retained earnings	1,901,853	1,970,824
Accumulated other comprehensive income	14,996	5,774
Treasury stock, at cost, 27,217,988 shares and 27,097,290 shares at December 31, 2009 and 2008, respectively	(618,592)	(616,969)
Total stockholders' equity	2,081,700	2,126,942
Total liabilities and stockholders' equity	$2,662,152	$2,712,817

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$ 599,287	$1,804,026	$1,741,647
Pressure pumping	161,441	217,494	202,812
Oil and natural gas	21,218	42,360	41,637
Total operating revenues	781,946	2,063,880	1,986,096
Operating costs and expenses:			
Contract drilling	357,742	1,038,327	963,150
Pressure pumping	111,414	132,570	105,273
Oil and natural gas	7,341	12,793	10,864
Depreciation, depletion and impairment	289,847	275,990	246,346
Selling, general and administrative	56,621	58,080	54,665
Embezzlement recoveries	—	—	(43,955)
Net loss (gain) on asset disposals	3,385	(4,163)	(16,432)
Other operating expenses	3,810	4,350	2,875
Total operating costs and expenses	830,160	1,517,947	1,322,786
Operating income (loss)	(48,214)	545,933	663,310
Other income (expense):			
Interest income	381	1,553	2,351
Interest expense	(4,148)	(630)	(2,187)
Other	426	502	363
Total other income (expense)	(3,341)	1,425	527
Income (loss) before income taxes	(51,555)	547,358	663,837
Income tax expense (benefit):			
Current	(119,038)	128,098	191,028
Deferred	101,443	65,392	38,322
Total income tax expense (benefit)	(17,595)	193,490	229,350
Income (loss) from continuing operations	(33,960)	353,868	434,487
Income (loss) from discontinued operations, net of income taxes	(4,330)	(6,799)	4,152
Net income (loss)	$ (38,290)	$ 347,069	$ 438,639
Basic income (loss) per common share:			
Income (loss) from continuing operations	$ (0.22)	$ 2.29	$ 2.78
Income (loss) from discontinued operations, net of income taxes	(0.03)	(0.04)	0.03
Net income (loss)	$ (0.25)	$ 2.25	$ 2.81
Diluted income (loss) per common share:			
Income (loss) from continuing operations	$ (0.22)	$ 2.27	$ 2.75
Income (loss) from discontinued operations, net of income taxes	(0.03)	(0.04)	0.03
Net income (loss)	$ (0.25)	$ 2.23	$ 2.78
Weighted average number of common shares outstanding:			
Basic	152,069	153,379	154,755
Diluted	152,069	154,358	156,612
Cash dividends per common share	$ 0.20	$ 0.60	$ 0.44

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock		Additional		Accumulated		
	Number of Shares	Amount	Paid-in Capital	Retained Earnings	Other Comprehensive Income	Treasury Stock	Total
				(In thousands)			
Balance, December 31, 2006	176,656	$1,766	$681,069	$1,346,542	$ 8,390	$(475,301)	$1,562,466
Comprehensive income:							
Net income	—	—	—	438,639	—	—	438,639
Foreign currency translation adjustment, (net of tax of $6,755)	—	—	—	—	11,817	—	11,817
Total comprehensive income	—	—	—	438,639	11,817	—	450,456
Issuance of restricted stock	601	6	(6)	—	—	—	—
Forfeitures of restricted stock	(101)	(1)	1	—	—	—	—
Exercise of stock options	230	2	2,048	—	—	—	2,050
Stock-based compensation	—	—	19,364	—	—	—	19,364
Tax benefit related to stock-based compensation	—	—	1,105	—	—	—	1,105
Payment of cash dividends	—	—	—	(68,561)	—	—	(68,561)
Purchase of treasury stock	—	—	—	—	—	(70,850)	(70,850)
Balance, December 31, 2007	177,386	1,773	703,581	1,716,620	20,207	(546,151)	1,896,030
Comprehensive income:							
Net income	—	—	—	347,069	—	—	347,069
Foreign currency translation adjustment, (net of tax of $8,368)	—	—	—	—	(14,433)	—	(14,433)
Total comprehensive income	—	—	—	347,069	(14,433)	—	332,636
Issuance of restricted stock	577	6	(6)	—	—	—	—
Forfeitures of restricted stock	(75)	(1)	1	—	—	—	—
Exercise of stock options	2,304	23	25,525	—	—	—	25,548
Stock-based compensation	—	—	20,131	—	—	—	20,131
Tax benefit related to stock-based compensation	—	—	16,280	—	—	—	16,280
Payment of cash dividends	—	—	—	(92,865)	—	—	(92,865)
Purchase of treasury stock	—	—	—	—	—	(70,818)	(70,818)
Balance, December 31, 2008	180,192	1,801	765,512	1,970,824	5,774	(616,969)	2,126,942
Comprehensive income (loss):							
Net loss	—	—	—	(38,290)	—	—	(38,290)
Foreign currency translation adjustment, (net of tax of $5,347)	—	—	—	—	9,222	—	9,222
Total comprehensive loss	—	—	—	(38,290)	9,222	—	(29,068)
Issuance of restricted stock	604	6	(6)	—	—	—	—
Vesting of restricted stock units	6	—	—	—	—	—	—
Forfeitures of restricted stock	(56)	—	—	—	—	—	—
Exercise of stock options	83	1	568	—	—	—	569
Stock-based compensation	—	—	18,565	—	—	—	18,565
Tax expense related to stock-based compensation	—	—	(3,004)	—	—	—	(3,004)
Payment of cash dividends	—	—	—	(30,681)	—	—	(30,681)
Purchase of treasury stock	—	—	—	—	—	(1,623)	(1,623)
Balance, December 31, 2009	180,829	$1,808	$781,635	$1,901,853	$ 14,996	$(618,592)	$2,081,700

The accompanying notes are an integral part of these consolidated financial statements.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ (38,290)	$ 347,069	$ 438,639
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and impairment	289,847	275,990	246,346
Provision for bad debts	3,810	4,350	2,875
Dry holes and abandonments	129	1,617	1,309
Deferred income tax expense	101,443	65,392	38,322
Stock-based compensation expense	18,214	19,688	18,873
Net loss (gain) on asset disposals	3,385	(4,163)	(16,432)
Tax expense related to stock-based compensation	(3,004)	—	—
Changes in operating assets and liabilities:			
Accounts receivable	213,813	(30,777)	100,429
Income taxes receivable/payable	(108,664)	(11,258)	7,174
Inventory and other assets	14,178	2,498	2,211
Accounts payable	(52,673)	6,486	(37,412)
Accrued expenses	(21,178)	(4,474)	(5,640)
Other liabilities	(92)	1,242	1,434
Net cash provided by operating activities of discontinued operations	32,759	1,344	14,096
Net cash provided by operating activities	453,677	675,004	812,224
Cash flows from investing activities:			
Acquisitions	—	—	(29,000)
Purchases of property and equipment	(452,646)	(445,426)	(604,604)
Proceeds from disposal of assets	3,359	11,436	34,054
Net cash used in investing activities of discontinued operations	(54)	(3,286)	(2,912)
Net cash used in investing activities	(449,341)	(437,276)	(602,462)
Cash flows from financing activities:			
Purchases of treasury stock	(1,623)	(70,818)	(70,850)
Dividends paid	(30,681)	(92,865)	(68,561)
Tax benefit related to stock-based compensation	—	16,280	1,105
Proceeds from borrowings under revolving credit facility	—	—	142,500
Repayment of borrowings under revolving credit facility	—	(50,000)	(212,500)
Revolving credit facility issuance costs	(6,169)	—	—
Proceeds from exercise of stock options	569	25,548	2,050
Net cash used in financing activities	(37,904)	(171,855)	(206,256)
Effect of foreign exchange rate changes on cash	2,222	(2,084)	543
Net increase (decrease) in cash and cash equivalents	(31,346)	63,789	4,049
Cash and cash equivalents at beginning of year	81,223	17,434	13,385
Cash and cash equivalents at end of year	$ 49,877	$ 81,223	$ 17,434
Supplemental disclosure of cash flow information:			
Net cash (paid) received during the year for:			
Interest expense	$ (1,804)	$ (323)	$ (1,808)
Income taxes	14,029	(126,331)	(176,281)
Non-cash investing and financing activities:			
Net increase (decrease) in payables for purchases of property and equipment	$ (25,110)	$ (3,590)	$ 597
Net (increase) decrease in deposits on equipment purchases	43,029	(42,293)	23,095

The accompanying notes are an integral part of these consolidated financial statements.

1. Description of Business and Summary of Significant Accounting Policies

A description of the business and basis of presentation follows:

Description of business — Patterson-UTI Energy, Inc., through its wholly-owned subsidiaries (collectively referred to herein as "Patterson-UTI" or the "Company"), is a leading provider of onshore contract drilling services to major and independent oil and natural gas operators in Texas, New Mexico, Oklahoma, Arkansas, Louisiana, Mississippi, Colorado, Utah, Wyoming, Montana, North Dakota, Pennsylvania, West Virginia and western Canada. The Company provides pressure pumping services primarily in the Appalachian Basin. The Company also owns and invests in oil and natural gas assets as a working interest owner primarily in Texas and New Mexico.

Basis of presentation — The consolidated financial statements include the accounts of Patterson-UTI and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated. Except for wholly-owned subsidiaries, the Company has no controlling financial interests in any entity which would require consolidation.

The U.S. dollar is the functional currency for all of the Company's operations except for its Canadian operations, which use the Canadian dollar as its functional currency. The effects of exchange rate changes are reflected in accumulated other comprehensive income, which is a separate component of stockholders' equity.

A summary of the significant accounting policies follows:

Management estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from such estimates.

Revenue recognition — Revenues are recognized when services are performed, except for revenues earned under turnkey contract drilling arrangements which are recognized using the completed contract method of accounting. The Company follows the percentage-of-completion method of accounting for footage contract drilling arrangements. Under the percentage-of-completion method, management estimates are relied upon in the determination of the total estimated expenses to be incurred drilling the well. Due to the nature of turnkey contract drilling arrangements and risks therein, the Company follows the completed contract method of accounting for such arrangements. Under this method, all drilling revenues and expenses related to a well in progress are deferred and recognized in the period the well is completed. Provisions for losses on incomplete or in-process wells are made when estimated total expenses are expected to exceed estimated total revenues. The Company recognizes reimbursements received from third parties for out-of-pocket expenses incurred as revenues and accounts for these out-of-pocket expenses as direct costs. Except for two wells drilled under footage contracts in 2009, all of the wells the Company drilled during the years ended December 31, 2009, 2008 and 2007 were under daywork contracts.

Accounts receivable — Trade accounts receivable are recorded at the invoiced amount. The allowance for doubtful accounts represents the Company's estimate of the amount of probable credit losses existing in the Company's accounts receivable. The Company reviews the adequacy of its allowance for doubtful accounts at least quarterly. Significant individual accounts receivable balances and balances which have been outstanding greater than 90 days are reviewed individually for collectibility. Account balances, when determined to be uncollectible, are charged against the allowance.

Inventories — Inventories at December 31, 2009 consist primarily of chemical products and sand to be used in conjunction with the Company's pressure pumping activities. Inventories at December 31, 2008 consisted primarily of chemical products to be used in conjunction with the Company's drilling and completion fluids activities. The inventories are stated at the lower of cost or market, determined by the first-in, first-out method.

Property and equipment — Property and equipment is carried at cost less accumulated depreciation. Depreciation is provided on the straight-line method over the estimated useful lives. The method of depreciation does not change when equipment becomes idle. The estimated useful lives, in years, are shown below:

	Useful Lives
Drilling rigs and other equipment	2-15
Buildings	15-20
Other	3-12

Long-lived assets, including property and equipment, are evaluated for impairment when certain triggering events or changes in circumstances indicate that the carrying values may not be recoverable over their estimated remaining useful life.

Oil and natural gas properties — Working interests in oil and natural gas properties are accounted for using the successful efforts method of accounting. Under the successful efforts method of accounting, exploration costs which result in the discovery of oil and natural gas reserves and all development costs are capitalized to the appropriate well. Exploration costs which do not result in discovering oil and natural gas reserves are charged to expense when such determination is made. Costs of exploratory wells are initially capitalized to wells in progress until the outcome of the drilling is known. The Company reviews wells in progress quarterly to determine whether sufficient progress is being made in assessing the reserves and the economic operating viability of the respective projects. If no progress has been made in assessing the reserves and the economic operating viability of a project after one year following the completion of drilling, the Company considers the costs of the well to be impaired and recognizes the costs as expense. Geological and geophysical costs, including seismic costs, and costs to carry and retain undeveloped properties are charged to expense when incurred. The capitalized costs of both developmental and successful exploratory type wells, consisting of lease and well equipment, lease acquisition costs and intangible development costs, are depreciated, depleted and amortized on the units-of-production method, based on engineering estimates of proved oil and natural gas reserves of each respective field.

The Company reviews its proved oil and natural gas properties for impairment when a triggering event occurs such as downward revisions in reserve estimates or decreases in oil and natural gas prices. Proved properties are grouped by field and undiscounted cash flow estimates are prepared based on management's expectation of future pricing over the lives of the respective fields. These estimates are then reviewed by an independent petroleum engineer. If the net book value of a field exceeds its undiscounted cash flow estimate, impairment expense is measured and recognized as the difference between its net book value and discounted cash flow. Unproved oil and natural gas properties are reviewed quarterly to assess potential impairment. The Company's intent to drill, lease expiration and abandonment of area are considered. Assessment of impairment is made on a lease-by-lease basis. If an unproved property is determined to be impaired, costs related to that property are expensed.

Goodwill — Goodwill is considered to have an indefinite useful economic life and is not amortized. The Company assesses impairment of its goodwill at least annually or on an interim basis if triggering events or circumstances indicate that the fair value of the asset may have decreased below its carrying value. As discussed in Note 5, the Company determined that goodwill in its drilling and completion fluids reporting unit was impaired in connection with its annual impairment testing performed as of December 31, 2008. As discussed in Note 2, the Company exited the drilling and completion fluids business in January 2010, and this impairment charge is included in the results of discontinued operations in the consolidated statements of operations for the year ended December 31, 2008.

Maintenance and repairs — Maintenance and repairs are charged to expense when incurred. Renewals and betterments which extend the life or improve existing property and equipment are capitalized.

Disposals — Upon disposition of property and equipment, the cost and related accumulated depreciation are removed and any resulting gain or loss is reflected in the consolidated statement of operations.

Net income (loss) per common share — The Company provides a dual presentation of its net income (loss) per common share in its consolidated statements of operations: Basic net income (loss) per common share ("Basic EPS") and diluted net income (loss) per common share ("Diluted EPS"). The Company adopted a new accounting standard on January 1, 2009, which clarified that share-based payment awards that entitle their holders to receive non-forfeitable dividends before vesting should be considered participating securities and, as such, should be included in the calculation of earnings-per-share using the two-class method. All earnings-per-share data presented for the years ended December 31, 2008 and 2007 have been adjusted retrospectively to conform with this accounting standard. The impact of this retrospective application to the year ended December 31, 2008 was to reduce Basic and Diluted EPS by $0.01. The impact of this retrospective application to the year ended December 31, 2007 was to reduce Basic EPS by $0.02 and to reduce Diluted EPS by $0.01.

Basic EPS excludes dilution and is computed by first allocating earnings between common stockholders and holders of non-vested shares of restricted stock. Basic EPS is then determined by dividing the earnings attributable to common stockholders by the weighted average number of common shares outstanding during the period, excluding non-vested shares of restricted stock.

Diluted EPS is based on the weighted average number of common shares outstanding plus the dilutive effect of potential common shares, including stock options, non-vested shares of restricted stock and restricted stock units. The dilutive effect of stock options and restricted stock units is determined using the treasury stock method. The dilutive effect of non-vested shares of restricted stock is based on the more dilutive of the treasury stock method or the two-class method, assuming a reallocation of undistributed earnings to common stockholders after considering the dilutive effect of potential common shares other than non-vested shares of restricted stock.

The following table presents information necessary to calculate income (loss) from continuing operations per share, income(loss) from discontinued operations per share and net income (loss) per share for the years ended December 31, 2009, 2008 and 2007 as well as potentially dilutive securities excluded from the weighted average number of diluted common shares outstanding, as their inclusion would have been anti-dilutive (in thousands, except per share amounts):

	2009	2008	2007
BASIC EPS:			
Income (loss) from continuing operations	$ (33,960)	$353,868	$434,487
Adjust for (income) loss attributed to holders of non-vested restricted stock	313	(3,279)	(3,886)
Income (loss) from continuing operations attributed to common stockholders	$ (33,647)	$350,589	$430,601
Income (loss) from discontinued operations, net	$ (4,330)	$ (6,799)	$ 4,152
Adjust for (income) loss attributed to holders of non-vested restricted stock	38	64	(37)
Income (loss) from discontinued operations attributed to common stockholders	$ (4,292)	$ (6,735)	$ 4,115
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	152,069	153,379	154,755
Basic income (loss) from continuing operations per common share	$ (0.22)	$ 2.29	$ 2.78
Basic income (loss) from discontinued operations per common share	(0.03)	(0.04)	0.03
Basic net income (loss) per common share	$ (0.25)	$ 2.25	$ 2.81

	2009	2008	2007
DILUTED EPS:			
Income (loss) from continuing operations attributed to common stockholders	$ (33,647)	$350,589	$430,601
Add incremental earnings related to potential common shares	—	15	39
Adjusted income (loss) from continuing operations attributed to common stockholders	$ (33,647)	$350,604	$430,640
Weighted average number of common shares outstanding, excluding non-vested shares of restricted stock	152,069	153,379	154,755
Add dilutive effect of potential common shares	—	979	1,857
Weighted average number of diluted common shares outstanding	152,069	154,358	156,612
Diluted income (loss) from continuing operations per common share	$ (0.22)	$ 2.27	$ 2.75
Diluted income (loss) from discontinued operations per common share	(0.03)	(0.04)	0.03
Diluted net income (loss) per common share	$ (0.25)	$ 2.23	$ 2.78
Potentially dilutive securities excluded as anti-dilutive	8,090	2,455	2,460

Income taxes — The asset and liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for operating loss and tax credit carryforwards and for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. If applicable, a valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that such assets will be realized.

The Company adopted a new accounting standard on January 1, 2007 which clarified the accounting for uncertainty in income taxes recognized in an enterprise's financial statements and prescribed a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As a result of the adoption of this standard in 2007, the Company reduced a reserve for an uncertain tax position related to a prior business combination that had originally been recorded as goodwill in its contract drilling segment. The impact of this adjustment was to reduce goodwill in the contract drilling segment by approximately $2.9 million upon adoption of the new standard. The impact of adjustments to reserves with respect to other uncertain tax positions was not material. The Company's policy is to account for interest and penalties with respect to income taxes as operating expenses.

Stock based compensation — The Company recognizes the cost of share-based payments under the fair-value-based method. Under this method, compensation cost related to share-based payments is measured based on the estimated fair value of the awards at the date of grant, net of estimated forfeitures. This expense is recognized over the expected life of the awards (See Note 11).

Statement of cash flows — For purposes of reporting cash flows, cash and cash equivalents include cash on deposit and money market funds.

Subsequent Events — The Company has performed an evaluation of subsequent events through February 19, 2010 at the time of issuance of the consolidated financial statements.

Recently Issued Accounting Standards — In June 2008, the FASB issued an accounting standard which clarifies that share-based payment awards that entitle their holders to receive non-forfeitable dividends before vesting should be considered participating securities and, as such, should be included in the calculation of basic earnings-per-share using the two-class method. Certain of the Company's share-based payment awards entitle the holders to receive non-forfeitable dividends. This standard is effective for financial statements issued for fiscal years beginning after December 15, 2008, as well as interim periods within those years, and became effective for the Company on January 1, 2009. The impact of the adoption of this standard is discussed in this Note 1.

In December 2008, the SEC issued a Final Rule, *Modernization of Oil and Gas Reporting* ("Final Rule"). The Final Rule revises certain oil and gas reporting disclosures in Regulation S-K and Regulation S-X under the Securities Act, and the Exchange Act, as well as Industry Guide 2. The amendments are designed to modernize and update oil and gas disclosure requirements to align them with current practices and changes in technology. The disclosure requirements are effective for registration statements filed on or after January 1, 2010 and for annual financial statements filed on or after December 31, 2009. The Company applied the provisions of the Final Rule in connection with its December 31, 2009 oil and natural gas reserve estimation process. The application of the Final Rule did not have a material impact on the Company.

In April 2009, the FASB issued a staff position to provide additional guidance for determining whether a market for a financial asset is not active and a transaction is not distressed for fair value measurements under generally accepted accounting principles. The provisions of this staff position are effective for financial statements issued for interim and annual periods ending after June 15, 2009 and became effective for the Company in the quarter ended June 30, 2009. The adoption of this staff position did not have a material impact on the Company.

In June 2009, the FASB issued a new accounting standard that amends the accounting and disclosure requirements for the consolidation of variable interest entities. This new standard removes the previously existing exception from applying consolidation guidance to qualifying special-purpose entities and requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. Before this new standard, generally accepted accounting principles required reconsideration of whether an enterprise is the primary beneficiary of a variable interest entity only when specific events occurred. This new standard is effective as of the beginning of each reporting entity's first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. This new standard became effective for the Company on January 1, 2010. The adoption of this standard did not impact the Company's consolidated financial statements.

In June 2009, the FASB issued the FASB Accounting Standards Codification ("Codification"). Effective for financial statements issued for interim and annual periods ending after September 15, 2009, the Codification became the source of authoritative U.S. generally accepted accounting principles. The FASB will no longer issue new standards in the form of Statements, FASB Staff Positions or EITF Abstracts. Instead, it will issue Accounting Standards Updates to update the Codification. The adoption of the Codification did not impact the Company's consolidated financial statements.

Reclassifications — Certain reclassifications have been made to the 2008 and 2007 consolidated financial statements in order for them to conform with the 2009 presentation. These reclassifications had no impact on the Company's financial position, results of operations or cash flows.

2. Discontinued Operations

On January 20, 2010, the Company exited the drilling and completion fluids services business, which had previously been presented as one of the Company's reportable operating segments. On that date, the Company's wholly owned subsidiary, Ambar Lone Star Fluids Services LLC, completed the sale of substantially all of its assets, excluding billed accounts receivable. The sales price was approximately $44.3 million, subject to any post-closing adjustments to reflect the actual assets transferred as of the closing date. Upon the Company's exit from the drilling and completion fluids services business, the Company classified its drilling and completion fluids operating segment as a discontinued operation. Accordingly, the results of operations of this business have been reclassified and presented as results of discontinued operations for all periods presented in these consolidated financial statements. As of December 31, 2009, the assets to be disposed of are considered held for sale and are presented separately under the caption "Assets held for sale" in the consolidated balance sheet. These assets are included in the balance sheet at fair value less transaction costs. The fair value of the assets to be disposed of was estimated to be approximately $44.3 million based on the expected sales price described above. The source of this estimate was from a third party and it is considered a level 2 input in the fair value hierarchy of fair value accounting. Costs to sell the disposal group were estimated to be $1.9 million. An impairment charge of $1.9 million was recognized to reduce the carrying value of the disposal group to its estimated fair value less costs to sell.

Summarized operating results from discontinued operations for the years ended December 31, 2009, 2008 and 2007 are shown below (in thousands):

	2009	2008	2007
Drilling and completion fluids revenues	$79,786	$145,246	$128,098
Income (loss) before income taxes	$ (6,538)	$ (4,410)	$ 6,970
Income tax benefit (expense)	2,208	(2,389)	(2,818)
Income (loss) from discontinued operations	$ (4,330)	$ (6,799)	$ 4,152

The loss before income taxes in 2008 includes $9.96 million in non-deductible charges resulting from the impairment of goodwill. As a result, income tax expense was incurred for the year despite the fact that the discontinued operation had a pre-tax book loss.

The components of assets held for sale at December 31, 2009 are shown below (in thousands):

Assets held for sale:	
Inventory	$28,620
Unbilled accounts receivable	6,587
Prepaid expenses and other current assets	324
Property and equipment, net	8,793
Reserve to reduce disposal group to fair value less costs to sell	(1,900)
Total assets held for sale	$42,424

3. Acquisitions

On October 9, 2007, the Company acquired three recently refurbished SCR electric land-based drilling rigs and spare drilling equipment for $29.0 million. The transaction was accounted for as an acquisition of assets and the purchase price was allocated among the assets acquired based on their estimated fair market values.

4. Property and Equipment

Property and equipment consisted of the following at December 31, 2009 and 2008 (in thousands):

	2009	2008
Equipment	$ 3,230,737	$ 2,897,431
Oil and natural gas properties	93,354	89,809
Buildings	56,563	61,529
Land	9,795	10,196
	3,390,449	3,058,965
Less accumulated depreciation and depletion	(1,280,047)	(1,121,853)
Property and equipment, net	$ 2,110,402	$ 1,937,112

Depreciation, depletion and impairment — The following table summarizes depreciation, depletion and impairment expense related to property and equipment for 2009, 2008 and 2007 (in millions):

	2009	2008	2007
Depreciation and impairment expense	$280.6	$264.5	$232.9
Depletion expense	9.2	11.5	13.4
Total	$289.8	$276.0	$246.3

The Company evaluates the recoverability of its long-lived assets whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable. In light of adverse market conditions affecting the Company beginning in the fourth quarter of 2008 and continuing into 2009, including a substantial decrease in the operating levels of certain of its business segments, a significant decline in oil and natural gas commodity prices, and the results of the Company's annual goodwill impairment test at December 31, 2008 (see Note 5), the Company deemed it necessary to assess the recoverability of long-lived assets within its contract drilling and drilling and completion fluids segments in 2008. Due to a continued decrease in the operating levels in its contract drilling business segment through the first three quarters of 2009, the Company again deemed it necessary to assess the recoverability of long-lived assets within that segment during 2009. With respect to the long-lived assets in the Company's oil and natural gas exploration and production segment, the Company assesses the recoverability of long-lived assets at the end of each quarter due to revisions in its oil and natural gas reserve estimates and expectations about future commodity prices. The Company concluded that its pressure pumping segment was not subject to the negative events and trends, to the same degree as the contract drilling segment, and thus did not require further assessment of recoverability.

The Company performs the first step of its impairment assessments by comparing the undiscounted cash flows for each long-lived asset or asset group to its respective carrying value. Based on the results of these impairment tests, the carrying amounts of long-lived assets in the contract drilling and oil and natural gas segments were determined to be recoverable, except as described below.

The Company's analysis indicated that the carrying amounts of certain oil and natural gas properties were not recoverable at various testing dates in 2009, 2008 and 2007. The Company's estimates of expected future net cash flows from impaired properties are used in measuring the fair value of such properties. The Company recorded impairment charges of $3.7 million, $4.4 million and $3.9 million in 2009, 2008 and 2007, respectively, related to its oil and natural gas properties. The Company determined the fair value of the impaired assets using internally developed unobservable inputs (level 3 inputs in the fair value hierarchy of fair value accounting).

During 2009 and 2008, in connection with its long term planning process, the Company evaluated its then-current fleet of marketable drilling rigs and identified 23 and 22 rigs, respectively, that it determined would no longer be marketed as rigs. Additionally, in 2009, the Company identified one rig which would be recommissioned in a different configuration. The components comprising these rigs were evaluated, and those components with continuing utility to the Company's other marketed rigs were transferred to other rigs or to yards to be used as spare equipment. The remaining components of these rigs were impaired and the associated net book value of $10.5 million in 2009 and $10.4 million in 2008 was expensed in the Company's consolidated statements of operations as an impairment charge. The components that were impaired were estimated to have no fair value. The Company determined the fair value of the impaired assets using internally developed unobservable inputs (level 3 inputs in the fair value hierarchy of fair value accounting).

5. Goodwill

Goodwill by operating segment as of December 31, 2009 and 2008 and changes for the years then ended are as follows (in thousands):

	2009	2008
Contract Drilling:		
Balance as of January 1:		
Goodwill	$86,234	$86,234
Accumulated impairment losses	—	—
	86,234	86,234
Changes to goodwill	—	—
Balance as of December 31:		
Goodwill	86,234	86,234
Accumulated impairment losses	—	—
	86,234	86,234
Drilling and Completion Fluids (Discontinued Operations):		
Balance as of January 1:		
Goodwill	9,964	9,964
Accumulated impairment losses	(9,964)	—
	—	9,964
Impairment	—	(9,964)
Balance as of December 31:		
Goodwill	9,964	9,964
Accumulated impairment losses	(9,964)	(9,964)
	—	—
Total goodwill as of December 31	$86,234	$86,234

Goodwill is evaluated at least annually to determine if the fair value of recorded goodwill has decreased below its carrying value. For purposes of impairment testing, goodwill is evaluated at the reporting unit level. The Company's reporting units for impairment testing have been determined to be its operating segments. Goodwill as of December 31, 2009 and 2008 is recorded in the Company's contract drilling segment. Prior to 2008, goodwill was also recorded in the Company's drilling and completion fluids segment.

In connection with its annual goodwill impairment assessment performed as of December 31, 2008, the Company performed an impairment test of goodwill recorded in its contract drilling and drilling and completion fluids reporting units. In light of the adverse market conditions affecting the Company's common stock price beginning in the fourth quarter of 2008 and continuing into 2009, including a significant decrease in the number of its rigs operating and a significant decline in oil and natural gas commodity prices, the Company utilized a discounted cash flow methodology to estimate the fair values of its reporting units. In completing its first step of the analysis, the Company used a three-year projection of discounted cash flows, plus a terminal value determined using the constant growth method to estimate the fair value of its reporting units. In developing these fair value estimates, the Company applied key assumptions, including an assumed discount rate of 13.99% for all reporting units, an assumed long-term growth rate of 3.50% for the contract drilling reporting unit and an assumed long-term growth rate of 2.00% for the drilling and completion fluids reporting unit.

Based on the results of the first step of the impairment test in 2008, the Company concluded that no impairment was indicated in its contract drilling reporting unit as the estimated fair value of that reporting unit exceeded its carrying value. An impairment was indicated in the drilling and completion fluids reporting unit as the estimated fair value of that reporting unit was less than its carrying value. In validating this conclusion, the Company considered the results of its long-lived asset impairment tests and performed sensitivity analyses of the key assumptions used in deriving the respective fair values of its reporting units. The Company then performed the second step of the analysis of its drilling and completion fluids reporting unit, which included allocating the estimated fair value to the identifiable tangible and intangible assets and liabilities of this reporting unit based on their respective values. This allocation indicated that there was no residual value for goodwill, and accordingly the Company recorded an impairment charge of $9.964 million in the year ended December 31, 2008. As discussed in Note 2, the Company exited the drilling and completion fluids business on January 20, 2010, and the impairment charge recorded in 2008 is included in the loss from discontinued operations in the Company's statement of operations for the year ended December 31, 2008.

The Company again performed its annual goodwill impairment assessment as of December 31, 2009 related to the remaining $86.2 million in goodwill recorded in its contract drilling reporting unit. In completing its first step of the analysis, the Company used a three-year projection of discounted cash flows, plus a terminal value determined using the constant growth method to estimate the fair value of the reporting unit. In developing this fair value estimate, the Company applied key assumptions, including an assumed discount rate of 15.42% and an assumed long-term growth rate of 3.50%. Based on the results of the first step of the impairment test in 2009, the Company concluded that no impairment was indicated in its contract drilling reporting unit as the estimated fair value of that reporting unit exceeded its carrying value.

In the event that market conditions weaken, the Company may be required to record an impairment of goodwill in its contract drilling reporting unit in the future, and such impairment could be material.

6. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2009 and 2008 (in thousands):

	2009	2008
Salaries, wages, payroll taxes and benefits	$ 14,744	$ 30,334
Workers' compensation liability	66,015	70,439
Sales, use and other taxes	10,975	12,105
Insurance, other than workers' compensation	11,261	14,209
Other	6,613	5,658
	$109,608	$132,655

7. Asset Retirement Obligation

The Company records a liability for the estimated costs to be incurred in connection with the abandonment of oil and natural gas properties in the future. This liability is included in the caption "other liabilities" on the consolidated balance sheet. The following table describes the changes to the Company's asset retirement obligations during 2009 and 2008 (in thousands):

	2009	2008
Balance at beginning of year	$3,047	$1,593
Liabilities incurred	157	516
Liabilities settled	(354)	(424)
Accretion expense	118	59
Revision in estimated costs of plugging oil and natural gas wells	(13)	1,303
Asset retirement obligation at end of year	$2,955	$3,047

8. Borrowings Under Revolving Credit Facility

In March 2009, the Company entered into an unsecured revolving credit facility with a maximum borrowing capacity of $240 million, including a letter of credit sublimit of $150 million and a swing line sublimit of $40 million. In addition, the aggregate borrowing and letter of credit capacity under the revolving credit facility may, subject to the terms and conditions set forth therein including the receipt of additional commitments from lenders, be increased up to a maximum amount not to exceed $450 million.

Interest is paid on the outstanding principal amount of revolving credit facility borrowings at a floating rate based on, at the Company's election, LIBOR or a base rate. The margin on LIBOR loans ranges from 3.00% to 4.00% and the margin on base rate loans ranges from 2.00% to 3.00%, based on the Company's debt to capitalization ratio. At December 31, 2009, the margin on LIBOR loans would have been 3.00% and the margin on base rate loans would have been 2.00%. Any outstanding borrowings must be repaid at maturity on January 31, 2012 and letters of credit may remain in effect up to six months after such maturity date. This revolving credit facility includes various fees, including a commitment fee on the actual daily unused commitment (the commitment fee rate was 1.00% at December 31, 2009).

The Company incurred line of credit issuance costs of approximately $6.2 million during 2009 in connection with the revolving credit facility. These costs are being amortized to interest expense over the contractual term of the revolving credit facility.

There are customary representations, warranties, restrictions and covenants associated with the revolving credit facility. Financial covenants provide for a maximum debt to capitalization ratio and a minimum interest coverage ratio. As of December 31, 2009, the maximum debt to capitalization ratio was 35% and the minimum interest coverage ratio was 3.00 to 1. The Company does not expect that the restrictions and covenants will impact its ability to operate or react to opportunities that might arise.

As of December 31, 2009, the Company had no borrowings outstanding under the revolving credit facility. The Company had $46.3 million in letters of credit outstanding at December 31, 2009 and, as a result, had available borrowing capacity of approximately $194 million at that date. Each domestic subsidiary of the Company has unconditionally guaranteed the existing and future obligations of the Company and each other guarantor under the revolving credit facility and related loan documents, as well as obligations of the Company and its subsidiaries under any interest rate swap contracts that may be entered into with lenders party to the revolving credit facility.

9. Commitments, Contingencies and Other Matters

Commitments — As of December 31, 2009, the Company maintained letters of credit in the aggregate amount of $46.3 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which could become payable under the terms of the underlying insurance contracts. These letters of credit expire annually at various times during the year and are typically renewed. As of December 31, 2009, no amounts had been drawn under the letters of credit.

As of December 31, 2009, the Company had commitments to purchase approximately $186 million of major equipment.

Contingencies — The Company's contract services operations are subject to inherent risks, including blow-outs, cratering, fire and explosions which could result in personal injury or death, suspended drilling operations, damage to, or destruction of equipment, damage to producing formations and pollution or other environmental hazards.

As a protection against these hazards, the Company maintains general liability insurance coverage of $1.0 million per occurrence in excess of a $1.0 million self-insured retention for a total limit of $2.0 million per occurrence, with $10.0 million of aggregate coverage and excess liability and umbrella coverages up to $200 million per occurrence and in the aggregate. The Company maintains a $1.0 million per occurrence deductible on its workers' compensation, general liability and automobile liability insurance coverages. Accrued expenses related to insurance claims are set forth in Note 6.

The Company believes it is adequately insured for bodily injury and property damage to others with respect to its operations. However, such insurance may not be sufficient to protect the Company against liability for all consequences of personal injury, well disasters, extensive fire damage, or damage to the environment. The Company also carries insurance to cover physical damage to, or loss of, its rigs. However, it does not cover the full replacement cost of the rigs and the Company does not carry insurance against loss of earnings resulting from such damage. There can be no assurance that such insurance coverage will always be available on terms that are satisfactory to the Company, if at all.

The Company is party to various legal proceedings arising in the normal course of its business. The Company does not believe that the outcome of these proceedings, either individually or in the aggregate, will have a material adverse effect on its financial condition, results of operations or cash flows.

Other Matters — The Company has Change in Control Agreements with its Chairman of the Board, Chief Executive Officer, two Senior Vice Presidents and its General Counsel (the "Key Employees"). Each Change in Control Agreement generally has an initial term with automatic twelve month renewals unless the Company notifies the Key Employee at least ninety days before the end of such renewal period that the term will not be extended. If a change in control of the Company occurs during the term of the agreement and the Key Employee's employment is terminated (i) by the Company other than for cause or other than automatically as a result of death, disability or retirement, or (ii) by the Key Employee for good reason (as those terms are defined in the Change in Control Agreements), then the Key Employee shall generally be entitled to, among other things:

- a bonus payment equal to the greater of the highest bonus paid after the Change in Control Agreement was entered into and the average of the two annual bonuses earned in the two fiscal years immediately preceding a change in control (such bonus payment prorated for the portion of the fiscal year preceding the termination date);
- a payment equal to 2.5 times (in the case of the Chairman of the Board and Chief Executive Officer), 2 times (in the case of the Senior Vice Presidents) or 1.5 times (in the case of the General Counsel) of the sum of (i) the highest annual salary in effect for such Key Employee and (ii) the average of the three annual bonuses earned by the Key Employee for the three fiscal years preceding the termination date; and
- continued coverage under the Company's welfare plans for up to three years (in the case of the Chairman of the Board and Chief Executive Officer) or two years (in the case of the Senior Vice Presidents and General Counsel).

Each Change in Control Agreement provides the Key Employee with a full gross-up payment for any excise taxes imposed on payments and benefits received under the Change in Control Agreements or otherwise, including other taxes that may be imposed as a result of the gross-up payment.

10. Stockholders' Equity

Cash Dividends — The Company paid cash dividends during the years ended December 31, 2007, 2008 and 2009 as follows:

	Per Share	Total (in thousands)
2007:		
Paid on March 30, 2007	$0.08	$12,527
Paid on June 29, 2007	0.12	18,860
Paid on September 28, 2007	0.12	18,690
Paid on December 28, 2007	0.12	18,484
Total cash dividends	$0.44	$68,561
2008:		
Paid on March 28, 2008	$0.12	$18,493
Paid on June 27, 2008	0.16	25,011
Paid on September 29, 2008	0.16	24,803
Paid on December 29, 2008	0.16	24,558
Total cash dividends	$0.60	$92,865

	Per Share	Total (in thousands)
2009:		
Paid on March 31, 2009	$0.05	$ 7,655
Paid on June 30, 2009	0.05	7,675
Paid on September 30, 2009	0.05	7,675
Paid on December 30, 2009	0.05	7,676
Total cash dividends	$0.20	$30,681

On February 10, 2010, the Company's Board of Directors approved a cash dividend on its common stock in the amount of $0.05 per share to be paid on March 30, 2010 to holders of record as of March 15, 2010. The amount and timing of all future dividend payments, if any, is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial condition, terms of the Company's credit facilities and other factors.

On August 1, 2007, the Company's Board of Directors approved a stock buyback program authorizing purchases of up to $250 million of the Company's common stock in open market or privately negotiated transactions. During the year ended December 31, 2007, the Company purchased 3,308,850 shares of its common stock under the program at a cost of approximately $70.4 million. During the year ended December 31, 2008, the Company purchased 3,502,047 shares of its common stock under the program at a cost of approximately $66.3 million. During the year ended December 31, 2009, the Company purchased 5,715 shares of its common stock under the program at a cost of approximately $79,000. As of December 31, 2009, the Company is authorized to purchase approximately $113 million of the Company's outstanding common stock under the program. Shares purchased under the program are accounted for as treasury stock.

Additionally, the Company purchased 114,983, 152,235 and 20,269 shares of treasury stock from employees during 2009, 2008 and 2007, respectively. These shares were purchased at fair market value upon the vesting of restricted stock to provide the employees with the funds necessary to satisfy payroll tax withholding obligations. The total purchase price for these shares was approximately $1.5 million, $4.5 million and $496,000 in 2009, 2008 and 2007, respectively. These purchases were made pursuant to the terms of the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan and not pursuant to the stock buyback program.

11. Stock-based Compensation

The Company uses share-based payments to compensate employees and non-employee directors. The Company recognizes the cost of share-based payments under the fair-value-based method. Prior to 2009, share-based awards consisted of equity instruments in the form of stock options, restricted stock or restricted stock units, with all such awards subject to service conditions and, in certain cases, performance conditions. Beginning in 2009, share-based awards also include cash-settled performance unit awards which are accounted for as liability awards. The Company issues shares of common stock when vested stock options are exercised, when restricted stock is granted and when restricted stock units vest.

The Company's shareholders have approved the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (the "2005 Plan"), and the Board of Directors adopted a resolution that no future grants would be made under any of the Company's other previously existing plans. During 2008, the Company amended the 2005 Plan to, among other things, increase the total number of shares authorized for grant from 6,250,000 to 10,250,000. The Company's share-based compensation plans at December 31, 2009 follow:

Plan Name	Shares Authorized for Grant	Awards Outstanding	Shares Available for Grant
Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended	10,250,000	4,980,068	2,545,524
Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan, as amended ("1997 Plan")	—	2,860,634	—
Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan ("2001 Plan")	—	214,136	—
Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan ("1996 Plan")	—	35,000	—

A summary of the 2005 Plan follows:

- The Compensation Committee of the Board of Directors administers the plan.
- All employees including officers and directors are eligible for awards.
- The Compensation Committee determines the vesting schedule for awards. Awards typically vest over one year for non-employee directors and 3 to 4 years for employees.
- The Compensation Committee sets the term of awards and no option term can exceed 10 years.
- All options granted under the plan are granted with an exercise price equal to or greater than the fair market value of the Company's common stock at the time the option is granted.
- The plan provides for awards of incentive stock options, non-incentive stock options, tandem and free-standing stock appreciation rights, restricted stock awards, other stock unit awards, performance share awards, performance unit awards and dividend equivalents. As of December 31, 2009, only non-incentive stock options, restricted stock awards, restricted stock units and performance unit awards had been granted under the plan.

Options granted under the 1997 Plan typically vest over three or five years as dictated by the Compensation Committee. These options have terms of no more than ten years. All options were granted with an exercise price equal to the fair market value of the related common stock at the time of grant. Restricted stock awards granted under the 1997 Plan typically vested over four years.

Options granted under the 2001 Plan typically vest over five years as dictated by the Compensation Committee. These options have terms of no more than ten years. All options were granted with an exercise price equal to the fair market value of the Company's common stock at the time of grant.

Options granted under the 1996 Plan typically vest over two or five years as dictated by the Compensation Committee. These options have terms of no more than ten years. All options were granted with an exercise price equal to the fair market value of the Company's common stock at the time of grant.

Stock Options — The Company estimates the grant date fair values of stock options using the Black-Scholes-Merton valuation model ("Black-Scholes"). Volatility assumptions are based on the historic volatility of the Company's common stock over the most recent period equal to the expected term of the options as of the date the options are granted. The expected term assumptions are based on the Company's experience with respect to employee stock option activity. Dividend yield assumptions are based on the expected dividends at the time the options are granted. The risk-free interest rate assumptions are determined by reference to United States Treasury yields. Weighted-average assumptions used to estimate grant date fair values for stock options granted in the years ended December 31, 2009, 2008 and 2007 follow:

	2009	2008	2007
Volatility	49.90%	37.04%	36.37%
Expected term (in years)	4.00	4.17	4.00
Dividend yield	1.67%	2.27%	1.97%
Risk-free interest rate	1.67%	2.91%	4.55%

Stock option activity for the year ended December 31, 2009 follows:

	Shares	Weighted-average exercise price
Outstanding at beginning of year	5,933,572	$21.20
Granted	1,037,500	$13.12
Exercised	(82,802)	$ 6.87
Expired	(46,500)	$18.76
Outstanding at end of year	6,841,770	$20.17
Exercisable at end of year	5,258,103	$21.18

Options outstanding at December 31, 2009 have an aggregate intrinsic value of approximately $4.7 million and a weighted-average remaining contractual term of 6.0 years. Options exercisable at December 31, 2009 have an aggregate intrinsic value of approximately $1.9 million and a weighted-average remaining contractual term of 5.1 years. Additional information with respect to options granted, vested and exercised during the years ended December 31, 2009, 2008 and 2007 follows:

	2009	2008	2007
Weighted-average grant-date fair value of stock options granted (per share)	$ 4.71	$ 7.20	$ 7.09
Grant-date fair value of stock options vested during the year (in thousands)	$6,973	$ 6,761	$5,613
Aggregate intrinsic value of stock options exercised (in thousands)	$ 510	$45,240	$3,186

As of December 31, 2009, options to purchase 1,583,667 shares were outstanding and not vested. All of these non-vested options are expected to ultimately vest. Additional information as of December 31, 2009 with respect to these non-vested options that are expected to vest follows:

Aggregate intrinsic value	$2.7 million
Weighted-average remaining contractual term	8.95 years
Weighted-average remaining expected term	3.03 years
Weighted-average remaining vesting period	1.98 years
Unrecognized compensation cost	$7.1 million

Restricted Stock — For all restricted stock awards to date, shares of common stock were issued when the awards were made. Non-vested shares are subject to forfeiture for failure to fulfill service conditions and, in certain cases, performance conditions. Non-forfeitable dividends are paid on non-vested shares of restricted stock. For restricted stock awards made prior to 2008, the Company uses the "graded-vesting" attribution method to recognize periodic compensation cost over the vesting period. For restricted stock awards made in 2008 and thereafter, the Company uses the straight-line method to recognize periodic compensation cost over the vesting period.

Restricted stock activity for the year ended December 31, 2009 follows:

	Shares	Weighted-average Grant Date Fair Value
Non-vested restricted stock outstanding at beginning of year	1,429,571	$28.49
Granted	603,600	$13.75
Vested	(745,715)	$27.97
Forfeited	(55,555)	$26.65
Non-vested restricted stock outstanding at end of year	1,231,901	$21.67

As of December 31, 2009, approximately 1,145,000 shares of non-vested restricted stock outstanding are expected to vest. Additional information as of December 31, 2009 with respect to these unvested shares follows:

Aggregate intrinsic value	$17.6 million
Weighted-average remaining vesting period	1.54 years
Unrecognized compensation cost	$13.9 million

Restricted Stock Units — For all restricted stock unit awards made to date, shares of common stock are not issued until the units vest. Restricted stock units are subject to forfeiture for failure to fulfill service conditions. Non-forfeitable cash dividend equivalents are paid on non-vested restricted stock units.

Restricted stock unit activity for the year ended December 31, 2009 follows:

	Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock units outstanding at beginning of year	17,500	$31.60
Granted	6,500	$14.39
Vested	(5,833)	$31.60
Forfeited	(2,000)	$14.39
Non-vested restricted stock units outstanding at end of year	16,167	$26.81

Performance Unit Awards. On April 28, 2009, the Company granted performance unit awards to certain executive officers (the "2009 Performance Units"). The 2009 Performance Units provide for those executive officers to receive a cash payment upon the achievement of certain performance goals established by the Company during a specified period. The performance period for the 2009 Performance Units is the period from April 1, 2009 through March 31, 2012. The performance goals for the 2009 Performance Units are tied to the Company's total shareholder return for the performance period as compared to total shareholder return for a peer group determined by the Compensation Committee. These goals are considered to be market conditions under the relevant accounting standards. Generally, the recipients will receive a base payment if the Company's total shareholder return is positive and, when compared to the peer group, is at or above the 25th percentile but less than the 50th percentile; two times the base if at or above the 50th percentile but less than the 75th percentile, and four times the base if at the 75th percentile or higher. The total base amount with respect to the 2009 Performance Units is approximately $1.7 million. As the 2009 Performance Units are to be settled in cash at the end of the performance period, the Company's pro-rated obligation is measured at estimated fair value at the end of each reporting period and as of December 31, 2009 this pro-rated obligation was approximately $859,000.

Dividends on Equity Awards — Non-forfeitable cash dividends and dividend equivalents paid on equity awards are recognized as follows:

- Dividends are recognized as reductions of retained earnings for the portion of restricted stock awards expected to vest.

- Dividends are recognized as additional compensation cost for the portion of restricted stock awards that are not expected to vest or that ultimately do not vest.
- Dividend equivalents are recognized as additional compensation cost for restricted stock units.

12. Leases

The Company incurred rent expense of $11.9 million, $31.5 million and $27.6 million for the years 2009, 2008 and 2007, respectively. Rent expense is primarily related to short-term equipment rentals that are passed through to customers. The Company's obligations under non-cancelable operating lease agreements are not material to the Company's operations or cash flows.

13. Income Taxes

Components of the income tax provision applicable to Federal, state and foreign income taxes for the years ended December 31, 2009, 2008 and 2007 are as follows (in thousands):

	2009	2008	2007
Federal income tax expense (benefit):			
Current	$(117,493)	$117,367	$169,634
Deferred	103,574	57,879	36,911
	(13,919)	175,246	206,545
State income tax expense (benefit):			
Current	(1,883)	6,475	16,174
Deferred	(1,875	7,070	987
	(3,758)	13,545	17,161
Foreign income tax expense (benefit):			
Current	338	4,256	5,220
Deferred	(256)	443	424
	82	4,699	5,644
Total income tax expense (benefit):			
Current	(119,038)	128,098	191,028
Deferred	101,443	65,392	38,322
Total income tax expense (benefit)	$ (17,595)	$193,490	$229,350

The difference between the statutory Federal income tax rate and the effective income tax rate for the years ended December 31, 2009, 2008 and 2007 is summarized as follows:

	2009	2008	2007
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	4.7	1.7	1.4
Permanent differences	(5.7)	(1.2)	(1.6)
Other, net	0.1	(0.2)	(0.3)
Effective tax rate	34.1%	35.3%	34.5%

The tax effect of significant temporary differences representing deferred tax assets and liabilities and changes therein were as follows (in thousands):

	December 31, 2009	Net Change	December 31, 2008	Net Change	December 31, 2007	Net Change	December 31, 2006
Deferred tax assets:							
Current:							
Net operating loss carryforwards	$ —	$ —	$ —	$ (374)	$ 374	$ (1,496)	$ 1,870
Workers' compensation allowance	24,624	(1,360)	25,984	(602)	26,586	223	26,363
Embezzlement costs	773	45	728	68	660	(13,634)	14,294
Other	18,843	(2,780)	21,623	3,219	18,404	3,903	14,501
	44,240	(4,095)	48,335	2,311	46,024	(11,004)	57,028
Non-current:							
Net operating loss carryforwards	4,872	4,872	—	—	—	(374)	374
AMT credit	—	—	—	(118)	118	—	118
Expense associated with employee stock options	9,129	2,500	6,629	1,381	5,248	2,186	3,062
Federal benefit of foreign deferred tax liabilities	9,160	(256)	9,416	443	8,973	424	8,549
Federal benefit of state deferred tax liabilities	9,772	2,702	7,070	1,643	5,427	735	4,692
Other	9,485	4,120	5,365	614	4,751	704	4,047
	42,418	13,938	28,480	3,963	24,517	3,675	20,842
Total deferred tax assets	86,658	9,843	76,815	6,274	70,541	(7,329)	77,870
Deferred tax liabilities:							
Current:							
Other	(11,363)	1,044	(12,407)	(1,753)	(10,654)	(2,493)	(8,161)
Non-current:							
Property and equipment basis difference	(413,113)	(110,786)	(302,327)	(70,362)	(231,965)	(28,465)	(203,500)
Other	(10,961)	(7,091)	(3,870)	8,172	(12,042)	(6,741)	(5,301)
	(424,074)	(117,877)	(306,197)	(62,190)	(244,007)	(35,206)	(208,801)
Total deferred tax liabilities	(435,437)	(116,833)	(318,604)	(63,943)	(254,661)	(37,699)	(216,962)
Net deferred tax liability	$(348,779)	$(106,990)	$(241,789)	$(57,669)	$(184,120)	$(45,028)	$(139,092)

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. The Company expects the deferred tax assets at December 31, 2009 and 2008 to be realized as a result of the reversal of existing taxable temporary differences giving rise to deferred tax liabilities and the generation of taxable income; therefore, no valuation allowance is necessary.

Other deferred tax assets consist primarily of the tax effect of various allowance accounts and tax-deferred expenses expected to generate future tax benefit of approximately $28 million. Other deferred tax liabilities consist primarily of the tax effect of receivables from insurance companies and tax-deferred income not yet recognized for tax purposes.

For income tax purposes, the Company generated approximately $450 million of Federal and state net operating losses during the year ended December 31, 2009. Of this amount, approximately $378 million will be carried back to prior years, and the remaining balance can be carried forward to future years. The net operating losses that can be carried forward, if unused, are scheduled to expire as follows: 2014 — $7 million; 2019 — $15 million and 2029 — $50 million.

The Company adopted a new accounting standard on January 1, 2007 which clarified the accounting for uncertainty in income taxes recognized in an enterprise's financial statements and prescribed a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As a result of the adoption of this standard in 2007, the Company reduced a reserve for an uncertain tax position related to a prior business combination that had originally been recorded as goodwill (see Note 5). The impact of adjustments to reserves with respect to other uncertain tax positions was not material. As of December 31, 2009, the Company had no unrecognized tax benefits. The Company has established a policy to account for interest and penalties related to uncertain income tax positions as operating expenses. As of December 31, 2009, the tax years ended December 31, 2006 through December 31, 2008 are open for examination by U.S. taxing authorities. As of December 31, 2009, the tax years ended December 31, 2005 through December 31, 2008 are open for examination by Canadian taxing authorities.

14. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company's operating results include expenses of approximately $2.8 million in 2009, $4.5 million in 2008 and $4.0 million in 2007 for the Company's cash contributions to the plan.

15. Business Segments

The Company's revenues, operating profits and identifiable assets are primarily attributable to three business segments: (i) contract drilling of oil and natural gas wells, (ii) pressure pumping services and (iii) the investment, on a working interest basis, in oil and natural gas properties. Each of these segments represents a distinct type of business. These segments have separate management teams which report to the Company's chief operating decision maker. The results of operations in these segments are regularly reviewed by the chief operating decision maker for purposes of determining resource allocation and assessing performance. As discussed in Note 2, the Company exited the drilling and completion fluids services business which previously was reported as a business segment in January 2010. Operating results for that business for the years ended December 31, 2009, 2008 and 2007 are presented as discontinued operations in the consolidated statements of operations.

Contract Drilling — The Company markets its contract drilling services to major and independent oil and natural gas operators. As of December 31, 2009, the Company had 341 marketable land-based drilling rigs, of which 73 of the drilling rigs were based in west Texas and southeastern New Mexico; 100 in north central and east Texas, northern Louisiana and Mississippi; 56 in the Rocky Mountain region (Colorado, Utah, Wyoming, Montana and North Dakota); 49 in south Texas; 28 in the Texas panhandle, Oklahoma and Arkansas; 20 in western Canada; and 15 in the Appalachian Basin.

For the years ended December 31, 2009, 2008 and 2007, contract drilling revenue earned in Canada was $45.4 million, $88.5 million and $72.9 million, respectively. Additionally, we had long-lived assets within our contract drilling segment located in Canada of $69.2 million and $67.2 million as of December 31, 2009 and 2008, respectively.

Pressure Pumping — The Company provides pressure pumping services primarily in the Appalachian Basin. Pressure pumping services consist primarily of well stimulation and cementing for the completion of new wells and remedial work on existing wells. Well stimulation involves processes inside a well designed to enhance the flow of oil, natural gas, or other desired substances from the well. Cementing is the process of inserting material between the hole and the pipe to center and stabilize the pipe in the hole.

Oil and Natural Gas — The Company has been engaged in the development, exploration, acquisition and production of oil and natural gas. Through October 31, 2007, the Company served as operator with respect to several properties and was actively involved in the development, exploration, acquisition and production of oil and natural gas. Effective November 1, 2007 the Company sold the related operations portion of its exploration and production business. The Company continues to own and invest in oil and natural gas assets as a working interest owner. The Company's oil and natural gas interests are located primarily in Texas and New Mexico.

The following tables summarize selected financial information relating to the Company's business segments (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Revenues:			
Contract drilling	$ 600,423	$1,808,600	$1,744,884
Pressure pumping	161,441	217,494	202,812
Oil and natural gas	21,218	42,360	41,637
Total segment revenues	783,082	2,068,454	1,989,333
Elimination of intercompany revenues(a)	(1,136)	(4,574)	(3,237)
Total revenues	$ 781,946	$2,063,880	$1,986,096
Income (loss) from continuing operations before income taxes:			
Contract drilling	$ (11,219)	$ 520,636	$ 558,792
Pressure pumping	1,017	42,019	64,257
Oil and natural gas	950	13,711	10,998
	(9,252)	576,366	634,047
Corporate and other	(35,577)	(34,596)	(31,124)
Embezzlement recoveries(b)	—	—	43,955
Net (loss) gain on asset disposals(c)	(3,385)	4,163	16,432
Interest income	381	1,553	2,351
Interest expense	(4,148)	(630)	(2,187)
Other	426	502	363
Income (loss) from continuing operations before income taxes	$ (51,555)	$ 547,358	$ 663,837
Identifiable assets:			
Contract drilling	$2,129,567	$2,255,421	$2,132,910
Pressure pumping	213,094	210,805	154,120
Oil and natural gas	25,355	31,760	37,885
Corporate and other(d)	294,136	214,831	140,284
Total assets	$2,662,152	$2,712,817	$2,465,199
Depreciation, depletion and impairment:			
Contract drilling	$ 248,424	$ 239,700	$ 213,812
Pressure pumping	27,589	19,600	14,311
Oil and natural gas	12,927	15,856	17,410
Corporate and other	907	834	813
Total depreciation, depletion and impairment	$ 289,847	$ 275,990	$ 246,346

	Years Ended December 31,		
	2009	2008	2007
Capital expenditures:			
Contract drilling	$ 395,376	$ 360,645	$ 539,506
Pressure pumping	43,144	61,289	47,582
Oil and natural gas	7,341	22,981	17,516
Corporate and other	6,785	511	—
Total capital expenditures	$ 452,646	$ 445,426	$ 604,604

(a) Includes contract drilling intercompany revenues related to drilling services provided for wells in which the Company owns a working interest.

(b) The Company's former CFO has pleaded guilty to criminal charges and has been sentenced and is serving a term of imprisonment arising out of his embezzlement of funds from the Company prior to his termination in 2005. The net embezzlement recovery in 2007 includes the recognition of the recovery of assets seized by a court appointed receiver, net of related professional fees.

(c) Net gains or losses associated with the disposal of assets relate to corporate strategy decisions of the executive management group. Accordingly, the related gains or losses have been separately presented and excluded from the results of specific segments.

(d) Corporate and other assets primarily include identifiable assets associated with the Company's former drilling and completion fluids segment as well as cash on hand managed by the parent corporation and certain deferred Federal income tax assets.

16. Concentrations of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of demand deposits, temporary cash investments and trade receivables.

The Company believes it has placed its demand deposits and temporary cash investments with high credit-quality financial institutions. At December 31, 2009 and 2008, the Company's demand deposits and temporary cash investments consisted of the following (in thousands):

	2009	2008
Deposits in FDIC and SIPC-insured institutions under insurance limits	$ 20,543	$ 588
Deposits in FDIC and SIPC-insured institutions over insurance limits	47,376	79,387
Deposits in foreign banks	4,383	18,805
	72,302	98,780
Less outstanding checks and other reconciling items	(22,425)	(17,557)
Cash and cash equivalents	$ 49,877	$ 81,223

Concentrations of credit risk with respect to trade receivables are primarily focused on companies involved in the exploration and development of oil and natural gas properties. The concentration is somewhat mitigated by the diversification of customers for which the Company provides services. As is general industry practice, the Company typically does not require customers to provide collateral. No significant losses from individual customers were experienced during the years ended December 31, 2009, 2008, or 2007. The Company recognized bad debt expense for 2009, 2008 and 2007 of $3.8 million, $4.4 million and $2.9 million, respectively.

The carrying values of cash and cash equivalents, trade receivables and accounts payable approximate fair value due to the short-term maturity of these items.

17. Related Party Transactions

Joint Operation of Oil and Natural Gas Properties — Through October 31, 2007, the Company served as operator with respect to several properties and was actively involved in the development, exploration, acquisition and production of oil and natural gas. Effective November 1, 2007, the Company sold the operations portion of its exploration and production business. The Company continues to own and invest in oil and natural gas assets as a working interest owner. During the time that the Company served as operator, it served as operator with respect to certain oil and natural gas properties in which certain of its affiliated persons have participated, either individually or through entities they control. These participations were typically through working interests in prospects or properties originated or acquired by Patterson Petroleum LLC, a wholly owned subsidiary of Patterson-UTI Energy, Inc.

During the time that the Company served as operator, sales of working interests to affiliated parties were made by the Company at its cost, comprised of the Company's costs of acquiring and preparing the working interests for sale plus a promote fee in some cases. These costs were paid by the working interest owners on a pro rata basis based upon their working interest ownership percentage. The price at which working interests were sold to affiliated persons was the same price at which working interests were sold to unaffiliated persons except that in some cases the affiliated persons also paid a promote fee. The affiliated persons received oil and natural gas production revenue (net of royalty) of $19.0 million from these properties in 2007. These persons or entities in turn paid for joint operating costs (including drilling and other development expenses) of $9.2 million incurred in 2007.

18. Quarterly Financial Information (in thousands, except per share amounts) (unaudited)

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2008				
Operating revenues	$472,004	$487,538	$572,798	$531,540
Operating income	119,191	122,364	166,126	138,252
Income from continuing operations, net of income taxes	76,354	75,184	110,047	92,282
Income (loss) from discontinued operations, net of income taxes	1,055	6,238	(1,301)	(12,790)
Net income	77,409	81,422	108,746	79,492
Basic income (loss) per common share:				
From continuing operations	$ 0.50	$ 0.48	$ 0.71	$ 0.60
From discontinued operations	$ 0.01	$ 0.04	$ (0.01)	$ (0.08)
Net income	$ 0.51	$ 0.52	$ 0.70	$ 0.52
Diluted income (loss) per common share:				
From continuing operations	$ 0.49	$ 0.48	$ 0.70	$ 0.60
From discontinued operations	$ 0.01	$ 0.04	$ (0.01)	$ (0.08)
Net income	$ 0.50	$ 0.52	$ 0.69	$ 0.52

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2009				
Operating revenues	$268,209	$140,497	$159,671	$213,569
Operating income (loss)	25,154	(25,855)	(24,619)	(22,894)
Income (loss) from continuing operations, net of income taxes	15,835	(16,891)	(16,814)	(16,090)
Income (loss) from discontinued operations, net of income taxes	368	(852)	(1,766)	(2,080)
Net income (loss)	16,203	(17,743)	(18,580)	(18,170)
Basic income (loss) per common share:				
From continuing operations	$ 0.10	$ (0.11)	$ (0.11)	$ (0.11)
From discontinued operations	$ 0.00	$ (0.01)	$ (0.01)	$ (0.01)
Net income (loss)	$ 0.10	$ (0.12)	$ (0.12)	$ (0.12)
Diluted income (loss) per common share:				
From continuing operations	$ 0.10	$ (0.11)	$ (0.11)	$ (0.11)
From discontinued operations	$ 0.00	$ (0.01)	$ (0.01)	$ (0.01)
Net income (loss)	$ 0.10	$ (0.12)	$ (0.12)	$ (0.12)

As discussed in Note 2, the Company exited the drilling and completion fluids services business in January 2010. The results of operations related to the drilling and completion fluids operating segment have been reclassified and presented as discontinued operations in the quarterly financial information above.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance	Charged to Costs and Expenses	Deductions(1)	Ending Balance
		(In thousands)		
Year Ended December 31, 2009				
Deducted from asset accounts:				
Allowance for doubtful accounts	$ 9,330	$4,700	$3,119	$10,911
Year Ended December 31, 2008				
Deducted from asset accounts:				
Allowance for doubtful accounts	$10,014	$4,350	$5,034	$ 9,330
Year Ended December 31, 2007				
Deducted from asset accounts:				
Allowance for doubtful accounts	$ 7,484	$2,550	$ 20	$10,014

(1) Uncollectible accounts written off net of recoveries.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Patterson-UTI Energy, Inc. has duly caused this Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

PATTERSON-UTI ENERGY, INC.

By: /s/ Douglas J. Wall

Douglas J. Wall
President and Chief Executive Officer

Date: February 19, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report on Form 10-K has been signed by the following persons on behalf of Patterson-UTI Energy, Inc. and in the capacities indicated as of February 19, 2010.

Signature	Title
/s/ Mark S. Siegel Mark S. Siegel	Chairman of the Board
/s/ Douglas J. Wall Douglas J. Wall *(Principal Executive Officer)*	President and Chief Executive Officer
/s/ John E. Vollmer III John E. Vollmer III *(Principal Financial Officer)*	Senior Vice President — Corporate Development, Chief Financial Officer and Treasurer
/s/ Gregory W. Pipkin Gregory W. Pipkin *(Principal Accounting Officer)*	Chief Accounting Officer and Assistant Secretary
/s/ Kenneth N. Berns Kenneth N. Berns	Senior Vice President and Director
/s/ Charles O. Buckner Charles O. Buckner	Director
/s/ Curtis W. Huff Curtis W. Huff	Director
/s/ Terry H. Hunt Terry H. Hunt	Director
/s/ Kenneth R. Peak Kenneth R. Peak	Director
/s/ Cloyce A. Talbott Cloyce A. Talbott	Director

EXHIBIT INDEX

3.1 Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).

3.2 Amendment to Restated Certificate of Incorporation, as amended (filed August 9, 2004 as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).

3.3 Second Amended and Restated Bylaws (filed August 6, 2007 as Exhibit 3.3 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007 and incorporated herein by reference).

4.1 Rights Agreement dated January 2, 1997, between Patterson Energy, Inc. and Continental Stock Transfer & Trust Company (filed January 14, 1997 as Exhibit 2 to the Company's Registration Statement on Form 8-A and incorporated herein by reference).

4.2 Amendment to Rights Agreement dated as of October 23, 2001 (filed October 31, 2001 as Exhibit 3.4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2001 and incorporated herein by reference).

4.3 Restated Certificate of Incorporation, as amended (See Exhibits 3.1 and 3.2).

4.4 Registration Rights Agreement with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned by REMY Capital Partners III, L.P. (filed March 19, 2002 as Exhibit 4.3 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).

10.1 For additional material contracts, see Exhibits 4.1, 4.2 and 4.4.

10.2 Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan (filed November 27, 2002 as Exhibit 4.4 to Post Effective Amendment No. 1 to the Company's Registration Statement on Form S-8 (File No. 333-60470) and incorporated herein by reference).*

10.3 Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan (filed July 28, 2003 as Exhibit 4.7 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 and incorporated herein by reference).*

10.4 Amendment to the Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan (filed August 9, 2004 as Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*

10.5 Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan (filed July 25, 2001 as Exhibit 4.4 to Post-Effective Amendment No. 1 to the Company's Registration Statement on Form S-8 (File No. 333-60466) and incorporated herein by reference).*

10.6 Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, including Form of Executive Officer Restricted Stock Award Agreement, Form of Executive Officer Stock Option Agreement, Form of Non-Employee Director Restricted Stock Award Agreement and Form of Non-Employee Director Stock Option Agreement (filed June 21, 2005 as Exhibit 10.1 to the Company's Current Report on Form 8-K, and incorporated herein by reference).*

10.7 First Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.8 Second Amendment to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan (filed June 6, 2008 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.9 Form of Cash-Settled Performance Unit Award Agreement pursuant to the Patterson-UTI Energy, Inc. 2005 Long-Term Incentive Plan, as amended from time to time.*

10.10 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Mark S. Siegel (filed on February 4, 2004 as Exhibit 10.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.11 Employment Agreement, dated as of September 1, 2007 between Patterson-UTI Energy, Inc. and Cloyce A. Talbott (filed on September 24, 2007 as Exhibit 10.1 to the Company's Current Report on Form 8-K, and incorporated herein by reference).*

10.12 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Kenneth N. Berns (filed on February 4, 2004 as Exhibit 10.5 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.13 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed on February 4, 2004 as Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.14 Form of Letter Agreement regarding termination, effective as of January 29, 2004, entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Kenneth N. Berns and John E. Vollmer III (filed on February 25, 2005 as Exhibit 10.23 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference).*

10.15 Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Cloyce A. Talbott, Douglas J. Wall, Kenneth N. Berns, Curtis W. Huff, Terry H. Hunt, Kenneth R. Peak, Charles O. Buckner, John E. Vollmer III, Seth D. Wexler and Gregory W. Pipkin (filed April 28, 2004 as Exhibit 10.11 to the Company's Annual Report on Form 10-K, as amended, for the year ended December 31, 2003 and incorporated herein by reference).*

10.16 Severance Agreement between Patterson-UTI Energy, Inc. and Douglas J. Wall, effective as of August 31, 2007 (filed September 4, 2007 as Exhibit 10.3 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.17 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of August 31, 2007, by and between Patterson-UTI Energy, Inc. and Douglas J. Wall (filed September 4, 2007 as Exhibit 10.2 to the Company's Current Report on Form 8-K and incorporated herein by reference).*

10.18 Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of November 2, 2009, by and between Patterson-UTI Energy, Inc. and Seth D. Wexler (filed November 2, 2009 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009 and incorporated herein by reference).*

10.19 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Mark S. Siegel, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.20 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Douglas J. Wall, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.21 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and John E. Vollmer, III, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.22 First Amendment to Change in Control Agreement Between Patterson-UTI Energy, Inc. and Kenneth N. Berns, entered into November 1, 2007 (filed November 5, 2007 as Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 and incorporated herein by reference).*

10.23 Credit Agreement dated March 20, 2009, among Patterson-UTI Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender, each of Amegy Bank, N.A., Comerica Bank, and HSBC Bank USA, N.A., as lender, Bank of America, N.A., as syndication agent, letter of credit issuer and lender, and The Bank of Tokyo-Mitsubishi UFJ, Ltd. as documentation agent and lender (filed March 25, 2009 as Exhibit 10.1 to the Company's Current Report on Form 8-K and incorporated herein by reference).

10.24 Commitment Increase and Joinder Agreement dated June 19, 2009, among the Company, as borrower, Regions Bank as the new lender, Bank of America, N.A. as a letter of credit issuer and Wells Fargo Bank, N.A., as administrative agent, letter of credit issuer, swing line lender and lender (filed August 4, 2009 as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q and incorporated herein by reference).

10.25 Letter Agreement dated February 6, 2006 between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed May 1, 2006 as Exhibit 10.25 to the Company's Annual Report on Form 10-K, as amended, and incorporated herein by reference).*

21.1 Subsidiaries of the Registrant.

23.1 Consent of Independent Registered Public Accounting Firm.

31.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.

31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended.
32.1	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	The following materials from Patterson-UTI Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2009, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Stockholders' Equity, (iv) the Consolidated Statements of Cash Flows, (v) Notes to Consolidated Financial Statements, tagged as blocks of text, and (vi) Valuation and Qualifying Accounts.

* Management Contract or Compensatory Plan identified as required by Item 15(a)(3) of Form 10-K.

EXHIBIT 31.1

CERTIFICATIONS

I, Douglas J. Wall, certify that,

1. I have reviewed this annual report on Form 10-K of Patterson-UTI Energy, Inc.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Douglas J. Wall

Douglas J. Wall
President and Chief Executive Officer

Date: February 19, 2010

EXHIBIT 31.2

CERTIFICATIONS

I, John E. Vollmer III, certify that:

1. I have reviewed this annual report on Form 10-K of Patterson-UTI Energy, Inc.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ John E. Vollmer III

John E. Vollmer III
Senior Vice President — Corporate Development,
Chief Financial Officer and Treasurer

Date: February 19, 2010

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

NOT FILED PURSUANT TO THE SECURITIES EXCHANGE ACT OF 1934

In connection with the Annual Report of Patterson-UTI Energy, Inc. (the "Company") on Form 10-K for the period ending December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Douglas J. Wall, Chief Executive Officer, and John E. Vollmer III, Chief Financial Officer, of the Company, each certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission upon request.

/s/ Douglas J. Wall

Douglas J. Wall
Chief Executive Officer
February 19, 2010

/s/ John E. Vollmer III

John E. Vollmer III
Chief Financial Officer
February 19, 2010

CORPORATE INFORMATION

CORPORATE OFFICE

Patterson-UTI Energy, Inc.
450 Gears Road, Suite 500
Houston, Texas 77067
Telephone: (281) 765-7100
Fax: (281) 765-7175
www.patenergy.com

COMMON STOCK

Nasdaq: PTEN

TRANSFER AGENT

Continental Stock
Transfer & Trust Company
17 Battery Place, 8th Floor
New York, NY 10004
Telephone: (212) 509-4000
www.continentalstock.com

INDEPENDENT AUDITOR

PricewaterhouseCoopers LLP

DIRECTORS

Mark S. Siegel
Chairman, Patterson-UTI Energy, Inc.;
President, Remy Investors and
Consultants, Incorporated

Kenneth N. Berns
Senior Vice President,
Patterson-UTI Energy, Inc.

Charles O. Buckner
Retired Partner,
Ernst & Young LLP

Curtis W. Huff
Managing Partner
Intervale Capital LLC

Terry H. Hunt
Energy Consultant
and Investor

Kenneth R. Peak
President and
Chief Executive Officer,
Contango Oil & Gas

Cloyce A. Talbott
Former President and
Chief Executive Officer,
Patterson-UTI Energy, Inc.

CORPORATE OFFICERS

Mark S. Siegel
Chairman

Douglas J. Wall
President and
Chief Executive Officer

Kenneth N. Berns
Senior Vice President

John E. Vollmer III
Senior Vice President –
Corporate Development,
Chief Financial Officer
and Treasurer

Seth D. Wexler
General Counsel
and Secretary

Gregory W. Pipkin
Chief Accounting Officer
and Assistant Secretary

PATTERSON-UTI
ENERGY INC.

Patterson-UTI Energy, Inc.
450 Gears Road, Suite 500
Houston, Texas 77067
Telephone: (281) 765-7100
Fax: (281) 765-7175

www.patenergy.com