PATTERSON UTI ENERGY INC
Form 10-K/A
March 17, 2006

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

Form 10-K/A
(Amendment No. 1)

(Mark One)

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

For the fiscal year ended December 31, 2004

or

o **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	**75-2504748**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
4510 Lamesa Highway, Snyder, Texas	**79549**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:
(325) 574-6300
Securities Registered Pursuant to 12(b) of the Act:
None
Securities Registered Pursuant to 12(g) of the Act:
(Title of class)
Common Stock, $.01 Par Value

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes þ No o

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2004, the last business day of the registrant s most recently completed second fiscal quarter was $2,648,551,638, calculated by reference to the closing price of $16.67 for the common stock on the Nasdaq National Market on that date.

As of February 24, 2005, the registrant had outstanding 168,651,600 shares of common stock, $.01 par value, its only class of voting common stock.

Documents incorporated by reference:

Definitive Proxy Statement for the 2005 Annual Meeting of Stockholders (Part III).

FORWARD LOOKING STATEMENTS

This Annual Report on Form 10-K/ A (including documents incorporated by reference herein) (the Report) contains statements with respect to our expectations and beliefs as to future events. These types of statements are forward-looking and subject to uncertainties. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the heading: Forward Looking Statements and Cautionary Statements for Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995 beginning on page 18.

This Annual Report on Form 10-K/ A, 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 Securities Exchange Act of 1934, are available 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.

EXPLANATORY NOTE

This Amendment No. 1 on Form 10-K/ A (Form 10-K/ A) to our Annual Report on Form 10-K for the year ended December 31, 2004, initially filed with the U.S. Securities and Exchange Commission (SEC) on February 25, 2005 (Original Filing), reflects a restatement of our Consolidated Financial Statements as discussed in Note 2 of the Notes to Consolidated Financial Statements. Previously issued financial statements are being restated to properly reflect losses incurred as a result of an embezzlement whereby payments were made to or for the benefit of Jonathan D. Nelson (Nelson), our former Chief Financial Officer (CFO), that had been reflected in previously issued financial statements as payments for assets and services that were not received by the Company. Previously issued financial statements are also being restated for the effects of the correction of other errors that are immaterial both individually and in the aggregate. These other adjustments relate primarily to previously reported property and equipment balances that result from our review of our property and equipment records and the underlying physical assets in connection with investigation of the embezzlement.

The total amount embezzled was approximately $77.5 million in cash, excluding any tax effects, beginning with the year ended December 31, 1998 through November 3, 2005 as follows (in thousands):

From 1998 to December 31, 2004	$	58,961
From January 1, 2005 to September 30, 2005		12,193
Total through September 30, 2005		71,154
From October 1, 2005 to November 3, 2005 (net of $1,500 repayment)		6,350
Total embezzlement	$	77,504

On November 16, 2005, the SEC obtained a freeze order on Nelson s assets (including assets held by entities controlled by him) and a Receiver was appointed to collect those assets. The Company understands that the Receiver will ultimately liquidate the assets and propose a plan to distribute the proceeds. While the Company believes it has a claim for at least the full amount embezzled, other creditors have or may assert claims on the assets held by the Receiver. As a result, recovery by the Company from the Receiver is uncertain as to timing and amount, if any. Recoveries, if any, will be recognized when they are considered collectable.

The effects of the embezzlement on the Company s financial position follow (in thousands):

Decrease in amounts previously reported	December 31, 2004	December 31, 2003
Assets(1)	$ (56,133)	$ (38,540)
Liabilities(2)	(20,848)	(15,044)
Retained earnings and stockholders equity	$ (35,285)	$ (23,496)

(1) The amount includes a decrease in Federal and state income taxes receivable of $1.0 million in 2003.

(2) Consists of an increase in Federal and state income taxes payable of $1.3 million in 2004 and decreases in deferred tax liabilities of $22.2 million and $15.0 million in 2004 and 2003, respectively.

The effects of the restatement due to the embezzlement and other adjustments on operating income as previously reported for 2004 and prior years, with no provision for potential recoveries, follow:

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands)				
Operating income (loss):					
As previously reported	$ 171,214	$ 87,190	$ 3,398	$ 267,172	$ 68,585
Adjustment for effects of embezzlement	(18,637)	(17,375)	(8,249)	(7,461)	(3,917)
Other adjustments	(4,110)	(3,533)	(2,041)	10	542
As restated	$ 148,467	$ 66,282	$ (6,892)	$ 259,721	$ 65,210

The effects of the restatement due to the embezzlement and other adjustments on net income as previously reported for 2004 and prior years follow:

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands, except per share data)				
Net income (loss):					
As previously reported	$ 108,733	$ 56,419	$ 2,374	$ 164,162	$ 37,226
Adjustments:					
Embezzled funds expense	(19,122)	(17,849)	(8,574)	(7,674)	(4,004)
Embezzlement amounts previously expensed as depreciation and selling, general and administrative	485	474	325	213	87
Embezzlement expense, net of amounts previously expensed	(18,637)	(17,375)	(8,249)	(7,461)	(3,917)
Other adjustments	(4,110)	(3,533)	(2,041)	10	542
Tax benefits	8,360	7,676	3,776	2,861	1,284
Net adjustment	(14,387)	(13,232)	(6,514)	(4,590)	(2,091)
Net income (loss) as restated	$ 94,346	$ 43,187	$ (4,140)	$ 159,572	$ 35,135
Net income (loss) per common share:					
Basic:					
As previously reported	$ 0.65	$ 0.35	$ 0.02	$ 1.07	$ 0.26
Adjustment for effects of embezzlement	$ (0.07)	$ (0.07)	$ (0.03)	$ (0.03)	$ (0.02)
Other adjustments	$ (0.02)	$ (0.01)	$ (0.01)	$	$
As restated	$ 0.57	$ 0.27	$ (0.03)	$ 1.04	$ 0.25
Diluted:					
As previously reported	$ 0.64	$ 0.34	$ 0.01	$ 1.04	$ 0.25
Adjustment for effects of embezzlement	$ (0.07)	$ (0.07)	$ (0.03)	$ (0.03)	$ (0.02)
Other adjustments	$ (0.02)	$ (0.01)	$ (0.01)	$	$
As restated	$ 0.56	$ 0.26	$ (0.03)	$ 1.01	$ 0.23

The effects of the restatement due to the embezzlement and other adjustments on selected balance sheet data as previously reported for 2004 and prior years follow:

	December 31,				
	2004	2003	2002	2001	2000
	(In thousands)				
Total assets:					
As previously reported	$ 1,322,911	$ 1,084,114	$ 942,823	$ 869,642	$ 739,898
Adjustment for effects of embezzlement:					
Property and equipment and other	(56,133)	(37,496)	(20,121)	(11,872)	(4,411)
Income taxes receivable		(1,044)	(807)	(531)	(507)
	(56,133)	(38,540)	(20,928)	(12,403)	(4,918)
Other adjustments:					
Property and equipment and other	(9,993)	(5,883)	(2,350)	(309)	(319)
Income taxes receivable		(170)	(171)	(75)	(75)
	(9,993)	(6,053)	(2,521)	(384)	(394)
As restated	$ 1,256,785	$ 1,039,521	$ 919,374	$ 856,855	$ 734,586
Stockholders equity:					
As previously reported	$ 1,007,539	$ 819,749	$ 737,731	$ 687,142	$ 481,299
Adjustment for effects of embezzlement	(35,285)	(23,496)	(12,499)	(7,373)	(2,777)
Other adjustments	(10,753)	(6,439)	(984)	572	(288)
As restated	$ 961,501	$ 789,814	$ 724,248	$ 680,341	$ 478,234
Working capital:					
As previously reported	$ 236,957	$ 199,613	$ 167,863	$ 110,172	$ 127,299
Adjustment for effects of embezzlement	(1,311)	(1,044)	(807)	(531)	(507)
Other adjustments	(166)	(170)	(171)	(75)	(75)
As restated	$ 235,480	$ 198,399	$ 166,885	$ 109,566	$ 126,717

The financial statements and related financial and statistical data contained in this Report have been restated to provide for, net of related tax effects, (1) the effects of losses incurred as a result of the embezzlement and (2) the effects of the correction of other errors that are immaterial both individually and in the aggregate.

Management has reassessed the effectiveness of our disclosure controls and procedures and has restated its report on internal control over financial reporting included as Item 9A of this Annual Report on Form 10-K/A.

Except for the foregoing amended information, this Form 10-K/ A continues to speak as of the date of the Original Filing, and we have not updated the disclosure contained herein to reflect events that occurred at a later date.

PART I

Items 1 and 2. ***Business and Properties.***

Overview

Based on publicly available information, we believe we are the second largest owner of land-based drilling rigs in North America. 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,
- Louisiana,
- Mississippi,
- Colorado,
- Utah,
- Wyoming, and
- Western Canada (Alberta, British Columbia and Saskatchewan).

As of December 31, 2004, we had a drilling fleet of 361 drilling rigs. A drilling rig includes the structure, power source and machinery necessary to cause a drill bit to penetrate earth to a depth desired by the customer.

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 provide drilling fluids, completion fluids and related services to oil and natural gas operators in Texas, Southeastern New Mexico, Oklahoma, the Gulf Coast region of Louisiana and the Gulf of Mexico. 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. We are also engaged in the development, exploration, acquisition and production of oil and natural gas. Our oil and natural gas operations are focused primarily in producing regions of West Texas, South Texas, Southeastern New Mexico, Utah and Mississippi.

Patterson/UTI Merger

Patterson Energy, Inc. and UTI Energy Corp. consummated a merger on May 8, 2001. The transaction was treated as a reorganization within the meaning of Section 368 (a) of the Internal Revenue Code of 1986, as amended, and accounted for as a pooling of interests for financial accounting purposes. Historical financial statements and related financial and statistical data contained in this Report have been restated to provide for the retroactive effect of the merger.

Industry Segments

Our revenues, operating results and identifiable operating assets are attributable to four industry segments:

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

With respect to these four segments:

- the contract drilling segment had operating profits in 2004, 2003 and 2002,
- the pressure pumping segment had operating profits in 2004, 2003 and 2002,
- the drilling and completion fluids segment had an operating profit in 2004 and operating losses in 2003 and 2002, and
- the oil and natural gas segment had operating profits in 2004, 2003 and 2002.

See Management s Discussion and Analysis of Financial Condition and Results of Operations and Note 17 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, 2004, we owned 361 drilling rigs which were based in the following regions:

- 149 in the Permian Basin region (West Texas and Southeastern New Mexico),
- 55 in South Texas,
- 42 in the Ark-La-Tex region and Mississippi,
- 77 in the Mid-Continent region (Oklahoma and North Central Texas),
- 21 in the Rocky Mountain region (Colorado, Utah and Wyoming), and
- 17 in Western Canada (Alberta, British Columbia and Saskatchewan).

Our drilling rigs have rated maximum depth capabilities ranging from 4,000 feet to 30,000 feet. Of our drilling rigs, 40 are SCR electric rigs and 321 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.

Drilling rigs are typically equipped with:

- engines,
- drawworks or hoists,
- derricks or masts,
- pumps to circulate the drilling fluid,
- blowout preventers,
- drill string (pipe), and
- other related equipment.

Over time, components on a drilling rig are replaced or rebuilt. We spend significant funds each year on an ongoing program to modify and upgrade our drilling rigs to ensure that our drilling equipment is well maintained and competitive. During fiscal years 2004, 2003 and 2002, we spent approximately $141 million, $77 million and $60 million, respectively, on capital improvements to modify and upgrade our drilling rigs.

Depth of the well and drill site conditions are the principal factors in determining the size of drilling rig used for a particular job. We use our rigs for developmental and exploratory drilling and they are capable of vertical or horizontal drilling.

Our contract drilling operations depend on the availability of:

- drill pipe,
- bits,
- replacement parts and other related rig equipment,
- fuel, and
- qualified personnel,

some of which 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. Typically, the contracts are short-term to drill a single well or a series of wells.

The 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. The contracts are generally subject to termination by the customer on short notice. We generally 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. The customers generally indemnify us against claims that might arise from other surface and subsurface pollution, except claims that might arise from our gross negligence.

The contracts provide for payment on a daywork, footage, or turnkey basis, or a combination thereof. In each case, we provide the rig and crews. Our bid for each contract 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.

Daywork Contracts

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 generally receive a lower rate when the drilling rig is moving, or when drilling operations are interrupted or restricted by conditions beyond our control. In addition, daywork contracts typically provide separately for mobilization of the drilling rig.

Footage 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 assumes certain risks associated with loss of the well from fire, blowouts and other risks.

Turnkey Contracts

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 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. However, given the increased exposure we have under a turnkey contract, profits can be significantly reduced and losses 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: daywork, footage and turnkey.

Revenues by Contract Type Information regarding our contract drilling activity for the last three years follows:

	Years Ended December 31,		
Type of Revenues	**2004**	**2003**	**2002**
Daywork	88%	83%	82%
Footage	6	7	11
Turnkey	6	10	7

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

	Years Ended December 31,		
	2004	**2003**	**2002**
Average rigs owned	359	336	323
Average rigs operating(1)	211	188	126
Average rig utilization rate	59%	56%	39%
Number of rigs operated	259	226	230
Number of wells drilled	3,534	3,017	2,012

(1) A rig is operating when it is drilling, being moved, assembled, dismantled or otherwise earning revenue under contract.

Drilling Rigs and Related Equipment Certain drilling rig information as of December 31, 2004 follows:

Depth Rating (Ft.)	**Mechanical**	**Electric**
4,000 to 9,999	63	
10,000 to 11,999	68	2
12,000 to 14,999	126	7
15,000 to 30,000	64	31
Totals	321	40

At December 31, 2004, we owned 288 trucks and 360 trailers used to rig down, transport and rig up our drilling rigs. This reduces our dependency upon third parties for these services and 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, New Mexico, Oklahoma, Utah 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. Generally, Appalachian Basin wells require cementing services before production commences. 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, 2004 follows:

- 23 cement pumper trucks,
- 26 fracturing pumper trucks,
- 24 nitrogen pumper trucks,
- 13 blender trucks,
- 12 bulk acid trucks,
- 28 bulk cement trucks,
- 8 bulk nitrogen trucks,
- 35 bulk sand trucks,
- 11 connection trucks, and
- 3 acid pumper trucks.

Drilling and Completion Fluids Operations

General We provide drilling fluids, completion fluids and related services to oil and natural gas operators in Texas, Southeastern New Mexico, Oklahoma, the Gulf Coast region of Louisiana and the Gulf of Mexico. We serve our offshore customers through six stockpoint facilities located along the Gulf of Mexico in Texas and Louisiana and our land-based customers through eleven stockpoint facilities in Texas, Louisiana, Oklahoma and New Mexico.

Drilling Fluids Drilling fluid products and systems are used to cool and lubricate the bit during drilling operations, contain formation pressures (thereby minimizing blowout risk), suspend and remove rock cuttings from the hole and maintain the stability of the wellbore. Technical services are provided to ensure that the products and systems are applied effectively to optimize drilling operations.

Completion Fluids After a well is drilled, the well casing is set and cemented into place. At that point, the drilling fluid services are complete and the drilling fluids are circulated out of the well and replaced with completion fluids. Completion fluids, also known as clear brine fluids, are solids-free, clear salt solutions that have high specific gravities. Combined with a range of specialty chemicals, these fluids are used to control bottom-hole pressures and to meet specific corrosion, inhibition, viscosity and fluid loss requirements.

Raw Materials Our drilling and completion fluids operations depend on the availability of the following raw materials:

Drilling	Completion
barite	calcium chloride
bentonite	calcium bromide zinc bromide

We obtain these raw materials through purchases made on the spot market and supply contracts with producers of these raw materials.

Barite Grinding Facility We own and operate a barite grinding facility with two barite grinding mills in Houma, Louisiana. This facility allows us to grind raw barite into the powder additive used in drilling fluids.

Other Equipment We own 20 trucks and 71 trailers and lease another 22 trucks which are used to transport drilling and completion fluids and related equipment.

Oil and Natural Gas Operations

General We are engaged in the development, exploration, acquisition and production of oil and natural gas. Our oil and natural gas business operates primarily in producing regions of West Texas, South Texas, Southeastern New Mexico, Utah and Mississippi. We significantly expanded our oil and natural gas operations in 2004 through our acquisition of TMBR/ Sharp Drilling, Inc. (TMBR). The oil and natural gas assets acquired in the acquisition of TMBR included both proved reserves and undeveloped properties. Management is assessing the acquired undeveloped prospects and will make determinations as to the extent future capital will be expended to develop those prospects. We also selectively acquire leasehold acreage and producing properties.

Oil and Natural Gas Reserves Estimates, derived from reserve reports provided by M. Brian Wallace, an independent petroleum engineer, of our proved reserves and estimated future net revenues from our proved reserves as of December 31, 2004, 2003 and 2002 are in the table below. The estimates were based upon production histories, current market prices for oil and natural gas, and other geologic, ownership and engineering data provided by us. The present values (discounted at 10% before income taxes) of estimated future net revenues shown in the table are not intended to represent the current market value of the estimated oil and natural gas reserves. For further information concerning the present value of estimated future net revenues from these proved reserves, see Note 21 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report.

Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reserves are considered proved if they are supported by either actual production or conclusive formation tests and future production is determined to be economical.

	As of December 31,		
	2004	2003	2002
	(In thousands)		
Proved Reserves:			
Oil (Bbls)	1,714	1,147	1,227
Gas (Mcf)	8,246	5,267	6,240
Total (BOE)	3,088	2,025	2,267
Estimated future net revenues before income taxes	$ 84,952	$ 47,873	$ 46,016
Present value of estimated future net revenues before income taxes, discounted at 10%	$ 59,519	$ 34,371	$ 32,308
Standardized measure of discounted future net cash flows(1)	$ 37,542	$ 23,950	$ 21,100

(1) For the calculation of standardized measure of discounted future net cash flows, see Note 21 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report.

A barrel (Bbl) of oil is 42 U.S. gallons and represents the basic unit for measuring production of crude oil and condensate.

An Mcf of natural gas refers to a volume of 1,000 cubic feet under prescribed conditions of pressure and temperature and represents the basic unit for measuring volumes of produced natural gas. A barrel of equivalent (BOE) in reference to natural gas equivalents is determined using the rate of six Mcf of natural gas to one Bbl of crude oil or condensate.

Production At December 31, 2004, we held a working interest in 440 productive wells, of which 266 were considered oil and 174 were considered natural gas. A productive well is a well producing oil or natural gas in commercial quantities. A working interest is the operating interest under an oil or natural gas lease which gives the owner the right to explore for and produce oil or natural gas from the lease. We were the operator of 199 of these productive wells at December 31, 2004. The following table sets forth our average net oil and natural gas production, average sales price and average production costs. Production costs are costs incurred to operate and maintain our wells and related equipment. These costs include labor, well service and repair, utilities, field supervision, property taxes, production and severance taxes and related charges.

	Years Ended December 31,		
	2004	**2003**	**2002**
Average net daily production:			
Oil (Bbls)	1,071	788	794
Gas (Mcf)	7,429	5,656	5,109
Total (BOE)	2,309	1,731	1,646
Average sales prices:			
Oil (per Bbl)	$ 39.12	$ 30.54	$ 25.02
Gas (per Mcf)	5.81	4.97	2.91
Average production costs (per BOE)	$ 7.18	$ 5.51	$ 5.11

Productive Wells The number of productive wells in which we held a working interest as of December 31, 2004 are in the table below. One or more completions in the same well bore are reflected as one well.

	Productive Wells	
	Gross	**Net**
Oil	266	53.26
Gas	174	24.65
Total	440	77.91

Developed and Undeveloped Acreage Developed and undeveloped acreage in which we owned a working interest at December 31, 2004 follows:

	Developed Acreage		Undeveloped Acreage	
Location	**Gross**	**Net**	**Gross**	**Net**
Texas	74,379	14,027	40,484	10,551
Kansas	320	45		
Louisiana	1,920	96		
New York	160	131		
New Mexico	19,959	3,943	23,693	3,943

Mississippi	2,920	668	8,366	1,840
Oklahoma	640	19		
Pennsylvania	880	129		
Utah			13,292	1,994
Total	101,178	19,058	85,835	18,328

Undeveloped acreage is leased acres on which wells have not been drilled to a point that would permit production of commercial quantities of oil and natural gas. Developed acreage is leased acres that have been assigned to productive wells. Our gross acreage is the total number of acres in which we own a working interest, regardless of the size of our working interest in the acreage. Our net acreage is the gross acreage proportionally reduced to our working interest percentage in the acreage.

Many of our leases summarized in the table above as undeveloped acreage will expire at the end of their respective primary terms unless production has been obtained from the acreage prior to that date. If production is obtained, the lease will remain in effect until the cessation of production. Undeveloped acreage subject to leases summarized in the table above are scheduled to expire as follows:

	Lease Acres Expiring	
	Gross	Net
Year ending:		
December 31, 2005	29,865	5,711
December 31, 2006	16,281	3,693
December 31, 2007 and later	39,689	8,924
Total	85,835	18,328

Drilling Activities The results of our participation in the drilling of developmental and exploratory wells during 2004, 2003 and 2002 follows:

	Developmental Wells				Exploratory Wells			
	Productive		Dry Holes		Productive		Dry Holes	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year ending:								
December 31, 2004	22	4.55			10	2.01	6	1.71
December 31, 2003	27	4.58	11	2.52	12	1.99	4	0.88
December 31, 2002	24	4.17	11	2.67	6	0.56	1	0.25

In addition, we were participating in nine wells, 1.92 net, that were being drilled at December 31, 2004.

Generally, a developmental well is a well that is drilled into an oil and natural gas reservoir that is known to be productive. An exploratory well is a well that is drilled to find oil and natural gas in an unproved area.

Customers

The customers of each of our four business segments are oil and natural gas operators or purchasers of these commodities. Our customer base includes both major and independent oil and natural gas operators. During 2004, no single customer accounted for 10% or more of our consolidated operating revenues.

Competition

Contract Drilling and Pressure Pumping Businesses Our land drilling and pressure pumping businesses are highly competitive. Often times, available land drilling rigs and pressure pumping equipment exceed the demand for such equipment. The equipment can also be moved from one market to another in response to market conditions.

Drilling and Completion Fluids Business The drilling and completion fluids industry is highly competitive and price is generally the most important factor. Other competitive factors include the availability of chemicals and experienced personnel, the reputation of the fluids services provider in the drilling industry and relationships with customers. Some of our competitors have substantially more resources and longer operating histories than we have.

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Oil and Natural Gas Business There is substantial competition for the acquisition of oil and natural gas leases suitable for development and exploration and for experienced personnel. Our competitors in this business include:

- major integrated oil and natural gas operators,
- independent oil and natural gas operators, and
- drilling and production purchase programs.

Our ability to increase our oil and natural gas reserves in the future is directly dependent upon our ability to select, acquire and develop suitable prospects. Many of our competitors have facilities and financial and human resources greater than ours.

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,
- 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 have not required the expenditure of significant resources. 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, which 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. Several state and Federal environmental laws and regulations currently apply to our operations and may become more stringent in the future.

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. 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.

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 is more comprehensive and stringent than previous oil pollution liability and prevention laws. It 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 oil and natural gas properties in each of the areas in which we operate and for each of the stockpoints operated by our drilling and completion fluids business. 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.

Our operations are also subject to Federal, state and local regulations for the control of air emissions. The Federal Clean Air Act, as amended, and various state and local laws impose certain air quality requirements on us. Amendments to the Clean Air Act revised the definition of major source such that emissions from both wellhead and associated equipment involved in oil and natural gas production may be added to determine if a source is a major source. As a consequence, more facilities may become major sources and thus would be required to obtain operating permits. This permitting process may require capital expenditures in order to comply with permit limits.

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 and financial condition.

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

- all-risk physical damages,
- employer s liability,
- commercial general liability, and
- workers compensation insurance.

We believe that we are adequately insured for public liability and property damage to others with respect to our operations. However, such insurance 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 coverage for major physical damage to our drilling rigs. However, 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 may not be supported by adequate insurance maintained by the customer.

Employees

We employed approximately 6,800 full-time persons (300 office personnel and 6,500 field personnel) at December 31, 2004. The number of field 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 pressure pumping division in Appalachia and our drilling operations in Canada are subject to slow periods of activity during the Spring thaw. In addition, our drilling operations in Canada are subject to slow periods of activity during the Fall.

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.

Incorporation by Reference

The various factors disclosed under the caption Forward Looking Statements and Cautionary Statements for Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995, beginning on page 18 of this Report, are incorporated by this reference into Items 1 and 2 of this Report. Readers of this Report should review those factors in conjunction with their review of Items 1 and 2.

Corporate Headquarters, Field Offices and Other Facilities

Our corporate headquarters are located in Snyder, Texas. We also have a number of offices, yards and stockpoint facilities located in our various operating areas.

Our corporate headquarters are located at 4510 Lamesa Highway, Snyder, Texas, and our telephone number at that address is (325) 574-6300. There are a number of improvements at our headquarters, including:

- office buildings with approximately 34,000 square feet of office space and storage,
- a shop facility with approximately 7,000 square feet used for drilling equipment repairs and metal fabrication,
- a truck shop facility with approximately 10,000 square feet used to maintain, overhaul and repair our truck fleet,
- an engine shop facility with approximately 20,000 square feet used to overhaul and repair the engines that power our drilling rigs, and
- an open-ended metal storage facility with approximately 10,000 square feet.

We have regional administrative offices, yards and stockpoint facilities in many of the areas in which we operate. The facilities are primarily used to support day-to-day operations, including the repair and maintenance of equipment as well as the storage of equipment, inventory and supplies and to facilitate administrative responsibilities and sales.

Contract Drilling Operations Our drilling services are supported by several administrative offices and yard facilities located throughout our areas of operations including:

- Texas,
- New Mexico,
- Oklahoma,
- Colorado,
- Utah,
- Wyoming, 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,
- West Virginia,
- Kentucky,

Wyoming, and

Tennessee.

Drilling and Completion Fluids Our drilling and completion fluids services are supported by several administrative offices and stockpoint facilities located throughout our areas of operations including:

Texas,

Louisiana,

New Mexico, and

Oklahoma.

Oil and Natural Gas Our oil and natural gas services are supported by administrative and field offices in Texas.

We own our headquarters 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 financial condition.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

None.

FORWARD LOOKING STATEMENTS AND CAUTIONARY STATEMENTS FOR PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

From time to time, we make written or oral forward-looking statements, including statements contained in this Annual Report on Form 10-K/A, our other filings with the SEC, press releases and reports to stockholders. These forward-looking statements are made pursuant to the Safe Harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements include, without limitation, statements relating to liquidity, financing of operations, sources and sufficiency of funds and impact of inflation. The words believes, budgeted, expects, project, will, could, may, plans, intends, strategy, or anticipates, and similar expressions are used to identify our forward-looking statements. We do not undertake to update, revise, or correct any of our forward-looking information.

We include the following cautionary statement in accordance with the Safe Harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statement made by us, or on our behalf. The factors identified in this cautionary statement are important factors (but not necessarily all of the important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement made by us, or on our behalf. Where any such forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results. The differences between assumed facts or bases and actual results can be material, depending upon the circumstances.

Where, in any forward-looking statement, we express an expectation or belief as to the future results, such expectation or belief is expressed in good faith and believed to have a reasonable basis. However, there can be no assurance that the statement of expectation or belief will result, or be achieved or accomplished. Taking this into account, the following are identified as important risk factors currently applicable to, or which could readily be applicable to, us:

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 Operations.

Our revenue, profitability and rate of growth are substantially dependent upon prevailing prices for oil and natural gas. For many years, oil and natural gas prices and, therefore, the level of drilling, exploration, development and production, 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. Natural gas prices fell from an average of $6.23 per Mcf in the first quarter of 2001 to an average of $2.51 per Mcf for the same period in 2002. During this same period, the average number of our rigs operating dropped by approximately 50%. The average market price of natural gas improved from $3.36 in 2002 to $5.45 in 2003 and $5.95 in 2004 resulting in an increase in demand for our drilling services. Our average number of rigs operating increased from 126 in 2002 to 188 in 2003 and to 211 in 2004. We expect oil and natural gas prices to continue to be volatile and to affect our financial condition and operations and ability to access sources of capital.

A General Excess of Operable Land Drilling Rigs Adversely Affects Our Profit Margins Particularly in Times of Weaker Demand.

The North American land drilling industry has experienced many downturns in demand over the last several years. 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.

In addition to adverse effects that future declines in demand could have on us, ongoing factors which could 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.

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. These price increases and delays in delivery may require us to increase capital and repairs expenditures in our contract drilling segment. Severe shortages could impair our ability to operate our drilling rigs.

The Various Business Segments in Which We Operate Are Highly Competitive with Excess Capacity which may Adversely Affect Our Operating Results.

Our land drilling and pressure pumping businesses are highly competitive. Often 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 for the foreseeable future 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.

The drilling and completion fluids services industry is highly competitive. Price is generally the most important factor. Other competitive factors include the availability of chemicals and experienced personnel, the reputation of the fluids services provider in the drilling industry and relationships with customers. Some of our competitors have substantially more resources and longer operating histories than we have.

Labor Shortages Adversely Affect Our Operating Results.

During periods of increasing demand for contract drilling services, the industry experiences shortages of qualified drilling rig personnel. During these periods, our ability to attract and retain sufficient qualified personnel to market and operate our drilling rigs 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 in response to the increased demand for our contract drilling services. Additionally, wage rates for drilling personnel are likely to increase, resulting in greater operating costs.

Continued Growth Through Rig Acquisition is Not Assured.

We have increased our drilling rig fleet over the past several years through mergers and acquisitions. The land drilling industry has experienced significant consolidation over the past several years, and there can be no assurance that acquisition opportunities will continue to be available. Additionally, we are likely to continue to face intense competition from other companies for available acquisition opportunities.

There can be no assurance that we will:

- have sufficient capital resources to complete additional acquisitions,
- successfully integrate acquired operations and assets,
- effectively manage the growth and increased size,
- successfully deploy idle or stacked rigs,
- maintain the crews and market share to operate drilling rigs acquired, or
- successfully improve our financial condition, results of operations, business or prospects in any material manner as a result of any completed acquisition.

We may incur substantial indebtedness to finance future acquisitions and also may issue equity securities or convertible securities in connection with any such acquisitions. 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, pressure pumping, and drilling and completion fluids 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 the 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 such insurance prohibitive.

We have 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 insurance and our general liability insurance coverages. These levels of self-insurance expose us to increased operating costs and risks.

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

The drilling of oil and natural gas wells is subject to various Federal, state, foreign, and local laws, rules and regulations. The cost of compliance with these laws and regulations could be substantial. Failure to comply with these requirements could expose us to substantial civil and criminal penalties. In addition, Federal law imposes a variety of regulations 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 Federal law. Our operations and facilities are subject to numerous state and Federal 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.

Some of Our Contract Drilling Services are Done Under Turnkey and Footage Contracts, Which are Financially Risky.

A portion of our contract drilling is performed under turnkey and footage contracts, which involve significant risks. Under turnkey drilling contracts, we contract to drill a well to a certain depth under specified

conditions at a fixed price. Under footage contracts, we contract to drill a well to a certain depth under specified conditions at a fixed price per foot. The risk to us under these types of drilling contracts are greater than on a well drilled on a daywork basis. Unlike daywork contracts, we must bear the cost of services until the target depth is reached. In addition, we must assume most of the risk associated with the drilling operations, generally assumed by the operator of the well on a daywork contract, including blowouts, loss of hole from fire, machinery breakdowns and abnormal drilling conditions. Accordingly, if severe drilling problems are encountered in drilling wells under such contracts, we could suffer substantial losses.

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 enacted in 1988. 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.

PART II

Item 5. ***Market for Registrant s Common Equity and 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 National Market and is quoted under the symbol PTEN. Our common stock is included in the S&P MidCap 400 Index and several other market indexes. The following table provides high and low sales prices of our common shares for the periods indicated, adjusted to reflect the two-for-one stock split on June 30, 2004:

	High	Low
2004:		
First quarter	$ 19.20	$ 15.75
Second quarter	19.56	14.52
Third quarter	19.88	15.69
Fourth quarter	20.45	17.85
2003:		
First quarter	$ 17.75	$ 13.55
Second quarter	18.49	15.90
Third quarter	16.14	12.58
Fourth quarter	16.97	12.84

(b) Holders

As of January 24, 2005, there were approximately 940 holders of record and approximately 48,000 beneficial holders of our common shares.

(c) Dividends and Buyback Program

No dividend was declared or paid in 2003. On April 28, 2004, our Board of Directors approved the initiation of a quarterly cash dividend of $0.02 on each share of our common stock which was paid on June 2, 2004. Quarterly cash dividends in the amount of $0.02 per share were also paid on September 1, 2004 and December 1, 2004. Total cash dividends paid in 2004 were approximately $10 million. In February 2005, our Board of Directors approved an increase in the quarterly cash dividend on our common stock to $0.04 per share form $0.02 per share. The next quarterly cash dividend is to be paid to holders of record on February 28, 2005 and paid on March 4, 2005. On April 28, 2004, our Board of Directors authorized a two-for-one stock split in the form of a stock dividend which was distributed on June 30, 2004. The amount and timing of all future dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions, terms of our credit facilities and other factors.

On June 7, 2004, our Board of Directors authorized a stock buyback program for the purchase of up to $30 million of our outstanding common stock. Repurchases may be made from time to time as, in the opinion of management, market conditions warrant, in the open market or in privately negotiated transactions. We did not repurchase any of our shares in the fourth quarter of 2004.

(d) Securities Authorized for Issuance Under Equity Compensation Plans

Equity compensation to our employees, officers and directors as of December 31, 2004 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	8,635,720	$ 12.64	3,482,992(1)
Equity compensation plans not approved by security holders(2)	1,370,322	$ 9.74	78,161
Total	10,006,042	$ 12.24	3,561,153

(1) The Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan, as amended, allows for the grant of restricted shares and performance awards, in addition to stock options and stock appreciation rights, to key employees, officers and directors, which are subject to certain vesting and forfeiture provisions. Of the securities remaining available for future issuance under equity compensation plans approved by security holders in column (c), there are 2,997,992 securities available under this plan.

(2) The Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan was approved by the Board of Directors in July 2001. The terms of the Plan provide 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 may be awarded under the Plan. 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.

In July 2001, the Board of Directors approved option grants, not included in any of the stock option plans, for two non-employee directors. Each of the two non-employee directors was granted an option to purchase 24,000 shares of our common stock at an exercise price greater than the fair market value of our common stock on the grant date. The options vested in November 2001 and expire in November 2005. As of December 31, 2004, one of these options to purchase 24,000 shares of our common stock was outstanding.

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

This Annual Report on Form 10-K/A for the fiscal year ended December 31, 2004, amends and restates the financial statements and related financial information for all years presented herein. The determination to restate these financial statements and other information was made as a result of management s identification of an embezzlement. Further information on the restatement can be found in Note 2 to Consolidated Financial Statements included as a part of Item 8 of this Annual Report on Form 10-K/A.

Our selected consolidated financial data as of December 31, 2004, 2003, 2002, 2001 and 2000, and for each of the five years then ended 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. The historical financial data presented below, was previously reported as restated to provide for (i) the retroactive effect of the merger with UTI Energy Corp., on May 8, 2001 accounted for as a pooling of interest; (ii) the retroactive application of the equity method of accounting for our investment in TMBR and (iii) a two-for-one stock split that occurred in 2004. Certain reclassifications have been made to the historical financial data to conform with the 2004 presentation.

	Restated (See Note 2)				
	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands)				
Income Statement Data:					
Operating revenues:					
Contract drilling	$ 809,691	$ 639,694	$ 410,295	$ 839,931	$ 512,998
Pressure pumping	66,654	46,083	32,996	39,600	21,465
Drilling and completion fluids	90,557	69,230	69,943	94,456	32,053
Oil and natural gas	33,867	21,163	14,723	15,988	15,806
Total	1,000,769	776,170	527,957	989,975	582,322
Operating costs and expenses:					
Contract drilling	556,869	475,224	318,201	487,343	384,840
Pressure pumping	37,561	26,184	19,802	21,146	13,403
Drilling and completion fluids	76,503	61,424	60,762	80,034	26,545
Oil and natural gas	7,978	4,808	3,956	5,190	4,872
Depreciation, depletion, amortization and impairment	122,800	100,834	92,778	86,035	60,839
Selling, general and administrative	31,983	27,685	26,116	28,462	22,166
Bad debt expense	897	259	320	2,045	570
Merger costs				5,943	
Restructuring and other charges		(2,452)	4,700	7,202	
Embezzled funds expense	19,122	17,849	8,574	7,674	4,004
Gain on sale of assets	(1,411)	(1,927)	(360)	(820)	(127)

Total	852,302	709,888	534,849	730,254	517,112
Operating income (loss)	148,467	66,282	(6,892)	259,721	65,210
Other income (expense)	680	2,694	803	(677)	(8,481)
Income (loss) before income taxes and cumulative effect of change in accounting principle	149,147	68,976	(6,089)	259,044	56,729
Income tax expense (benefit)	54,801	25,320	(1,949)	99,472	21,594
Income (loss) before cumulative effect of change in accounting principle	94,346	43,656	(4,140)	159,572	35,135

	Restated (See Note 2)				
	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands)				
Cumulative effect of change in accounting principle, net of related income tax benefit of approximately $287		(469)			
Net income (loss)	$ 94,346	$ 43,187	$ (4,140)	$ 159,572	$ 35,135
Net income (loss) per common share:					
Basic:					
Income (loss) before cumulative effect of change in accounting principle	$ 0.57	$ 0.27	$ (0.03)	$ 1.04	$ 0.25
Cumulative effect of change in accounting principle	$	$	$	$	$
Net income (loss)	$ 0.57	$ 0.27	$ (0.03)	$ 1.04	$ 0.25
Diluted:					
Income (loss) before cumulative effect of change in accounting principle	$ 0.56	$ 0.27	$ (0.03)	$ 1.01	$ 0.23
Cumulative effect of change in accounting principle	$	$	$	$	$
Net income (loss)	$ 0.56	$ 0.26	$ (0.03)	$ 1.01	$ 0.23
Cash dividends per common share	$ 0.06	$	$	$	$
Weighted average number of common shares outstanding:					
Basic	166,258	161,272	157,410	152,814	142,414
Diluted	169,211	164,572	157,410	158,394	149,682

Balance Sheet Data:					
Total assets	$ 1,256,785	$ 1,039,521	$ 919,374	$ 856,855	$ 734,586
Long-term debt					79,416
Stockholders equity	961,501	789,814	724,248	680,341	478,234
Working capital	235,480	198,399	166,885	109,566	126,717

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

This Item 7 contains forward-looking statements, which are made pursuant to the Safe Harbor provisions of the Private Securities Litigation Reform Act of 1995.

This Annual Report on Form 10-K/A for the fiscal year ended December 31, 2004, amends and restates the financial statements and related financial information for all years presented herein. The determination to restate these financial statements and other information was made as a result of management s identification of an embezzlement. Further information on the restatement can be found in Note 2 to Consolidated Financial Statements included as a part of Item 8 of this Annual Report on Form 10-K/A.

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, we provide pressure pumping services and drilling and completion fluid services. In addition to the aforementioned contract services, we also engage in the development, exploration, acquisition and production of oil and natural gas. For the three years ended December 31, 2004, our operating revenues consisted of the following (dollars in thousands):

	2004		2003		2002	
Contract drilling	$ 809,691	81%	$ 639,694	82%	$ 410,295	78%
Pressure pumping	66,654	7	46,083	6	32,996	6
Drilling and completion fluids	90,557	9	69,230	9	69,943	13
Oil and natural gas	33,867	3	21,163	3	14,723	3
	$ 1,000,769	100%	$ 776,170	100%	$ 527,957	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, Louisiana, Mississippi, Colorado, Utah, Wyoming and Western Canada while our pressure pumping services are focused primarily in the Appalachian Basin. Our drilling and completion fluids services are provided to operators in Texas, Southeastern New Mexico, Oklahoma, the Gulf Coast region of Louisiana and the Gulf of Mexico. Our oil and natural gas operations are primarily focused in West Texas, South Texas, Southeastern New Mexico, Utah and Mississippi.

We have been a leading consolidator of the land-based contract drilling industry over the past several years increasing our drilling fleet to 361 rigs as of December 31, 2004. Based on publicly available information, we believe we are the second largest owner of land-based drilling rigs in North America. Our most significant transaction occurred in May 2001 when we merged with UTI Energy Corp. in a merger of equals which basically doubled our drilling fleet and added the pressure pumping services business. Growth by acquisition has been a corporate strategy intended to expand both revenues and profits.

The profitability of our business is most readily assessed by two primary indicators: our average number of rigs operating and our average revenue per operating day. During 2004, our average number of rigs operating increased to 211 from 188 in 2003 and our average revenue per operating day increased to $10,470 from $9,300 in 2003. Primarily due to these improved operating results, we experienced an increase of approximately $52 million in consolidated net income in 2004.

Our revenues, profitability and cash flows are highly dependent upon the market prices of oil and natural gas. During periods of improved commodity prices, the capital spending budgets of oil and natural gas operators tend to expand, which results in increased demand for our contract services. Conversely, in periods of time when these commodity prices deteriorate, the demand for our contract services generally weakens and we experience downward pressure on pricing for our services. In addition, our operations are highly impacted by competition, the availability of excess equipment, labor issues and various other factors which are more fully described as risk factors in our Forward Looking Statements and Cautionary Statements for Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995 contained on page 18 of this Report.

Management believes that the liquidity of our balance sheet as of December 31, 2004, which includes approximately $235.5 million in working capital (including $112 million in cash), no long term debt and a $200 million line of credit with availability of $151 million (net of outstanding letters of credit totaling $49 million) provides us with the ability to pursue acquisition opportunities, expand into new regions, make improvements to our property and equipment and survive downturns in our industry.

Commitments and Contingencies We have no commitments or contingencies which require disclosure in our financial statements other than letters of credit of approximately $49 million at December 31, 2004, maintained for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which may become payable under the terms of the underlying insurance contracts. No amounts have been drawn under the letters of credit.

Net income for the years ended December 31, 2004, 2003 and 2002 include embezzled funds expense of $19.1 million, $17.8 million and $8.6 million, respectively. On November 16, 2005, the SEC obtained a freeze order on Nelson s assets (including assets held by entities controlled by him) and a Receiver was appointed to collect those assets. The Company understands that the Receiver will ultimately liquidate the assets and propose a plan to distribute the proceeds. While the Company believes it has a claim for at least the full amount embezzled, other creditors have or may assert claims on the assets held by the Receiver. As a result, recovery by the Company from the Receiver is uncertain as to timing and amount, if any. Recoveries, if any, will be recognized when they are considered collectable. Net income for the year ended December 31, 2002, includes a charge of $4.7 million related to the financial failure in 2002 of a workers compensation insurance carrier that had provided coverage for us in prior years.

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, money markets and highly rated municipal and commercial bonds.

Description of business We conduct our contract drilling operations in Texas, New Mexico, Oklahoma, Louisiana, Mississippi, Colorado, Utah, Wyoming and Western Canada. As of December 31, 2004, we owned 361 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. We provide drilling fluids, completion fluids and related services to oil and natural gas operators in Texas, Southeastern New Mexico, Oklahoma, the Gulf Coast region of Louisiana and the Gulf of Mexico. 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. We are also engaged in the development, exploration, acquisition and production of oil and natural gas. Our oil and natural gas operations are focused primarily in producing regions in West Texas, South Texas, Southeastern New Mexico, Utah and Mississippi.

The North American land drilling industry has experienced many downturns in demand over the last several years. 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.

In addition to adverse effects that future declines in demand could have on us, ongoing factors which could adversely affect utilization rates and pricing, even in an environment of stronger oil and natural gas prices and increased drilling activity, include:

movement of drilling rigs from region to region,

reactivation of land-based drilling rigs, and

new construction of drilling rigs.

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.

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 assets for impairment when events or changes in circumstances indicate that the carrying values of certain assets either exceed their respective fair values or may not be recovered over their estimated remaining useful lives. 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 in our assessment of impairment assuming the following four-year industry cycle: one year projected with low utilization, one year projected as a recovery period with improving utilization and the remaining two years projecting higher utilization. Provisions for asset impairment are charged to income when estimated future cash flows, on an undiscounted basis, are less than the asset s net book value. Impairment charges are recorded based on discounted cash flows. There were no impairment charges to property and equipment during the years 2004, 2003 or 2002.

Oil and natural gas properties 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 determinations are made. In accordance with Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, (SFAS No. 19) 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 the related reserve classification. If the reserve classification is uncertain 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 an 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 provided 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 determine impairment. Our 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 of approximately $3.2 million, $1.4 million and $700,000 for the years ended December 31, 2004, 2003 and 2002, respectively, is included in depreciation, depletion, amortization and impairment in the accompanying financial statements.

Goodwill Goodwill is considered to have an indefinite useful economic life and is not amortized. As such, we assess impairment of our goodwill annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. With respect to our drilling and completion fluids business, the determination that no impairment existed as of December 31, 2004, was based on the segment s improved operating results in 2004 and on our expectations that these improved results will continue. If the improved results do not continue, all or part of the goodwill of approximately $10 million associated with that business segment may be determined to be impaired.

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, as described below. 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 estimated total revenues.

In accordance with Emerging Issues Task Force Issue No. 00-14, we recognize reimbursements received from third parties for out-of-pocket expenses incurred as revenues and account for out-of-pocket expenses as direct costs.

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,
- total expenses to be incurred on footage and turnkey drilling contracts,
- depreciation, depletion, and amortization,
- asset impairment,
- reserves for self-insured levels of insurance coverages, and
- fair values of assets and liabilities assumed.

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.

Related Party Transactions

We operate certain oil and natural gas properties in which certain of our affiliated persons have participated, either individually or through entities they control, in the prospects or properties in which we have an interest. These participations, which have been on a working interest basis, have been in prospects or properties we originated or acquired. At December 31, 2004, affiliated persons were working interest owners in 237 of 300 total wells we operated. We make sales of working interests to reduce our economic risk in the properties. Generally, it is more efficient for us to sell the working interests to these affiliated persons than to market them to unrelated third parties. Sales of working interests were made at cost, including our costs of acquiring and preparing the working interests for sale. 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.

Production revenues and joint interest costs of each of the affiliated persons during 2004 for all wells operated by us in which the affiliated persons have working interests are presented in the table below. These amounts do not necessarily represent their profits or losses from these interests because the joint interest costs do not include the parties related drilling and leasehold acquisition costs incurred prior to January 1, 2004. These activities resulted in a payable to the affiliated persons of approximately $1.2 million and $871,000 and a receivable from the affiliated persons of approximately $856,000 and $888,000 at December 31, 2004 and 2003, respectively.

	Year Ended December 31, 2004	
Name	**Production Revenues(1)**	**Joint Interest Costs(2)**
Cloyce A. Talbott	$ 186,971	$ 42,313
Anita Talbott(3)	76,423	22,591
Jana Talbott, Executrix to the Estate of Steve Talbott(3)	11,655	2,940
Stan Talbott(3)	9,320	4,366
John Evan Talbott Trust(3)	3,124	668
Lisa Beck and Stacy Talbott(3)	978,607	410,334
SSI Oil & Gas, Inc.(4)	163,584	263,123
IDC Enterprises, Ltd.(5)	12,019,230	6,462,580
Subtotal	13,448,914	7,208,915
A. Glenn Patterson	123,583	27,468
Robert Patterson(6)	8,476	2,518
Thomas M. Patterson(6)	8,476	2,518
Subtotal	140,535	32,504
Jonathan D. Nelson, former Chief Financial Officer	248,297	263,549
Total	$ 13,837,746	$ 7,504,968

(1) Revenues for production of oil and natural gas, net of state severance taxes.

(2) Includes leasehold costs, tangible equipment costs, intangible drilling costs and lease operating expense billed during that period. All joint interest costs have been paid on a timely basis.

(3) Anita Talbott is the wife of Cloyce A. Talbott. Stan Talbott, Lisa Beck and Stacy Talbott are Mr. Talbott s adult children. Steve Talbott is the deceased son of Mr. Talbott. John Evan Talbott is Mr. Talbott s grandson.

(4) SSI Oil & Gas, Inc. is beneficially owned 50% by Cloyce A. Talbott and directly owned 50% by A. Glenn Patterson.

(5) IDC Enterprises, Ltd. is 50% owned by Cloyce A. Talbott and 50% owned by A. Glenn Patterson.

(6) Robert and Thomas M. Patterson are A. Glenn Patterson s adult children.

In 2004, 2003 and 2002, we paid approximately $914,000, $740,000 and $279,000, respectively, to TMP Truck and Trailer LP (TMP), an entity owned by Thomas M. Patterson (son of A. Glenn Patterson), for certain equipment and metal fabrication services. Purchases from TMP were at current market prices.

In 2004 and 2003, we paid approximately $39,000 and $209,000, respectively, to Melco Services (Melco) for dirt contracting services and $44,000 and $59,000, respectively, to L&N Transportation (L&N) for water hauling services. Both entities are owned by Lance D. Nelson, brother of Jonathan D. Nelson. Purchases from Melco and L&N were at current market prices.

See Note 2 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report for information pertaining to fraudulent payments made to or for the benefit of Jonathan D. Nelson, our former CFO.

Liquidity and Capital Resources

As of December 31, 2004, we had working capital of $235.5 million including cash and cash equivalents of $112.4 million. For 2004, our sources of cash flow included:

- $203.2 million from operations,
- $24.5 million from the exercise of stock options and warrants, and
- $3.3 million from the sale of property and equipment.

We used approximately $205.0 million:

- to make capital expenditures for the betterment and refurbishment of our drilling rigs,
- for the acquisition and procurement of drilling equipment,
- to fund capital expenditures for our pressure pumping and drilling and completion fluids divisions, and
- to fund leasehold acquisition and development and exploration of oil and natural gas properties.

Additionally, $10.0 million was used to pay quarterly dividends on our common stock, $1.5 million was used to buy 100,000 shares of our common stock pursuant to the stock buyback program authorized by our Board of Directors on June 7, 2004 and issuance costs of $780,000 were incurred during 2004 relating to our new $200 million credit facility. As of December 31, 2004, $1.8 million of cash was pledged as collateral for losses which could become payable under the terms of our workers compensation insurance contracts and was therefore restricted as to use.

In February 2004, we completed the acquisition of TMBR in which one of our wholly-owned subsidiaries acquired 100% of the remaining outstanding shares of TMBR for a net cash payment of $32.5 million ($40.4 million paid to TMBR shareholders less $7.9 million in cash acquired in the transaction) and the issuance of 2.78 million shares of our common stock valued at $17.82 per share (adjusted to reflect the two-for-one stock split on June 30, 2004). The assets of TMBR included 18 land-based drilling rigs and related equipment, shop facilities, equipment yards and their oil and natural gas properties. The transaction was accounted for as a business combination and the purchase price was allocated among the assets acquired and liabilities assumed based on their estimated fair market values.

We replaced our prior credit facility in December 2004 with a five-year, $200 million unsecured revolving line of credit (LOC). Interest is to be paid on outstanding LOC balances at a floating rate ranging from LIBOR plus 0.625% to 1.0% or the prime rate. This arrangement includes various fees, including a commitment fee on the average daily unused amount (0.15% at December 31, 2004). There are customary restrictions and covenants associated with the LOC. Financial covenants provide for a maximum debt to capitalization ratio and a minimum interest coverage ratio. We do not expect that the restrictions and covenants will restrict our ability to operate or react to opportunities that might arise. Availability under the LOC is reduced by outstanding letters of credit which totaled $49 million at December 31, 2004. There were no outstanding borrowings under the LOC at December 31, 2004. We incurred approximately $445,000 in costs to terminate the previous $100 million credit facility. These costs were expensed in 2004.

In December 2004, we entered into an agreement to acquire the U.S. land drilling assets of Key Energy Services, Inc. for approximately $62 million. The assets include 25 active and 10 stacked land-based drilling rigs, related drilling equipment, four yard facilities and a rig moving fleet consisting of approximately 45 trucks and 100 trailers. This transaction was completed in January 2005 using approximately $62 million of cash.

In February 2005, our Board of Directors approved an increase in the quarterly cash dividend on the Company s common stock to $0.04 per share from $0.02 per share. The next quarterly cash dividend is to be paid to holders of record on February 28, 2005 and paid on March 4, 2005.

We believe that the current level of cash and short-term investments, together with cash generated from operations, should be sufficient to meet our capital needs. From time to time, acquisition opportunities are evaluated.

The timing, size or success of any acquisition and the associated capital commitments are unpredictable. Should opportunities for growth requiring capital arise, we believe we would be able to satisfy these needs through a combination of working capital, cash generated from operations, our existing credit facility and additional debt financing or equity financing. However, there can be no assurance that such capital would be available.

Results of Operations

Comparison of the years ended December 31, 2004 and 2003

A summary of operations by business segment for the years ended December 31, 2004 and 2003 follows:

	Restated (See Note 2)		
	Years Ended December 31,		
Contract Drilling	**2004**	**2003**	**% Change**
	(Dollars in thousands)		
Revenues	$ 809,691	$ 639,694	26.6%
Direct operating costs	$ 556,869	$ 475,224	17.2%
Selling, general and administrative	$ 4,417	$ 4,401	0.4%
Depreciation	$ 101,779	$ 87,255	16.6%
Operating income	$ 146,626	$ 72,814	101.4%
Operating days	77,355	68,798	12.4%
Average revenue per operating day	$ 10.47	$ 9.30	12.6%
Average direct operating costs per operating day	$ 7.20	$ 6.91	4.2%
Number of owned rigs at end of period	361	343	5.2%
Average number of rigs owned during period	359	336	6.8%
Average rigs operating	211	188	12.2%
Rig utilization percentage	59%	56%	5.4%
Capital expenditures	$ 140,945	$ 77,350	82.2%

The market price of natural gas remained high in 2004. In fact, the average market price of natural gas improved to $5.95 per Mcf in 2004 compared to $5.45 per Mcf in 2003, resulting in an increase in demand for our contract drilling services. Our average number of rigs operating increased to 211 in 2004 from 188 in 2003. The average market price of natural gas and our average rigs operating for each of the fiscal quarters in 2004 and 2003 follow:

	1st Quarter	**2nd Quarter**	**3rd Quarter**	**4th Quarter**
2004:				
Average natural gas price	$ 5.64	$ 6.13	$ 5.62	$ 6.42
Average rigs operating	197	203	216	229
2003:				
Average natural gas price	$ 5.91	$ 5.70	$ 4.88	$ 5.29
Average rigs operating	176	195	192	191

Revenues and direct operating costs increased as a result of the increased number of operating days, as well as an increase in the average revenue and direct operating costs per operating day in 2004. Average revenue per operating day increased as a result of increased demand and pricing for our contract drilling services. Significant capital expenditures were incurred during 2004 to activate additional drilling rigs to meet increased demand, to modify and upgrade our existing 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. Increased depreciation expense in 2004 was due primarily to capital expenditures in 2003 and 2004, as well as acquisitions.

Pressure Pumping	Years Ended December 31, 2004	2003	% Change
	(Dollars in thousands)		
Revenues	$ 66,654	$ 46,083	44.6%
Direct operating costs	$ 37,561	$ 26,184	43.5%
Selling, general and administrative	$ 7,234	$ 5,683	27.3%
Depreciation	$ 5,112	$ 3,774	35.5%
Operating income	$ 16,747	$ 10,442	60.4%
Total jobs	7,444	5,667	31.4%
Average revenue per job	$ 8.95	$ 8.13	10.1%
Average direct operating costs per job	$ 5.05	$ 4.62	9.3%
Capital expenditures	$ 17,705	$ 10,524	68.2%

Revenues and direct operating costs for our pressure pumping operations increased as a result of the increased number of jobs, as well as an increase in the average revenue and average direct operating costs per job. The increase in jobs in 2004 was largely due to our expanded operations in the Appalachian regions of Kentucky, Tennessee and West Virginia, as well as increased demand for our services resulting from the improved industry conditions as discussed in Contract Drilling above. Increased average revenue per job was due primarily to increased pricing for our services. Selling, general and administrative expenses increased largely as a result of the expanding operations of the pressure pumping segment. Increased depreciation expense during 2004 was largely due to the expansion of the pressure pumping segment during 2004 and 2003 and related expenditures to acquire necessary equipment to facilitate the growth. Capital expenditures increased in 2004 compared to 2003 due to further expansion of services into Tennessee and Wyoming as well as modifications and upgrades to existing equipment and facilities.

Drilling and Completion Fluids	Restated (See Note 2) Years Ended December 31, 2004	2003	% Change
	(Dollars in thousands)		
Revenues	$ 90,557	$ 69,230	30.8%
Direct operating costs	$ 76,503	$ 61,424	24.5%
Selling, general and administrative	$ 7,696	$ 7,447	3.3%
Depreciation	$ 2,156	$ 2,279	(5.4)%
Operating income (loss)	$ 4,202	$ (1,920)	N/A
Total jobs	2,205	1,931	14.2%
Average revenue per job	$ 41.07	$ 35.85	14.6%
Average direct operating costs per job	$ 34.70	$ 31.81	9.1%
Capital expenditures	$ 1,488	$ 912	63.2%

The number of jobs increased as a result of the improved industry conditions as discussed in Contract Drilling above, as well as increased drilling activity in the Gulf of Mexico. Revenues and direct operating costs increased in 2004 primarily as a result of the increased number of jobs, as well as an increase in the

average revenue and direct operating costs per job. Average revenue and direct operating costs per job increased primarily as a result of an increase in the number of larger jobs completed in the Gulf of Mexico.

Oil and Natural Gas Production and Exploration	**Years Ended December 31, 2004**	**2003**	**% Change**
	(Dollars in thousands)		
Revenues	$ 33,867	$ 21,163	60.0%
Direct operating costs	$ 7,978	$ 4,808	65.9%
Selling, general and administrative	$ 1,816	$ 1,489	22.0%
Depreciation, depletion and impairment	$ 13,309	$ 7,082	87.9%
Operating income	$ 10,764	$ 7,784	38.3%
Capital expenditures	$ 14,451	$ 10,015	44.3%
Average net daily oil production (Bbls)	1,071	788	35.9%
Average net daily gas production (Mcf)	7,429	5,656	31.3%
Average oil sales price (per Bbl)	$ 39.12	$ 30.54	28.1%
Average gas sales price (per Mcf)	$ 5.81	$ 4.97	16.9%

Oil and gas revenues and direct operating costs increased in 2004 compared to 2003, primarily due to the oil and natural gas properties acquired in the acquisition of TMBR during February 2004 and increased market prices received for oil and natural gas during 2004. Direct operating costs further increased as a result of approximately $600,000 of dry hole costs incurred during 2004. Depreciation, depletion and impairment expense increased in 2004 primarily as a result of increased production and an increase of approximately $1.8 million of expenses incurred to impair certain oil and natural gas properties.

Corporate and Other	**Restated (See Note 2) Years Ended December 31, 2004**	**2003**	**% Change**
	(Dollars in thousands)		
Selling, general and administrative	$ 10,820	$ 8,665	24.9%
Bad debt expense	$ 897	$ 259	246.3%
Depreciation	$ 444	$ 444	%
Gain on sale of assets	$ 1,411	$ 1,927	(26.8)%
Other	$	$ (2,452)	N/A
Embezzled funds expense	$ 19,122	$ 17,849	7.1%
Interest income	$ 1,140	$ 1,116	2.2%
Interest expense	$ 695	$ 292	138.0%
Other income	$ 235	$ 1,870	(87.4)%

Selling, general and administrative expenses increased primarily as a result of increased professional expenses (including expenses incurred during 2004 to comply with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002) and additional compensation expense related to the issuance of restricted shares to certain key employees. Embezzled funds expense includes fraudulent payments made to or for the benefit of Jonathan D. Nelson, our former

CFO, for assets and services that were not received by the Company. Interest expense in 2004 included approximately $445,000 of termination fees and other related charges incurred as a result of the replacement of our credit facility. Other in 2003 includes a $2.5 million payment received as settlement for contract drilling services previously provided in Mexico by our wholly-owned subsidiary, Norton Drilling Company Mexico, Inc. The receivable had been reserved as uncollectible at the time of our acquisition of Norton Drilling Company Mexico, Inc. in 1999. Other income in 2003 includes approximately $1.7 million representing our pro rata share of the net income of TMBR using the equity method of accounting.

Comparison of the years ended December 31, 2003 and 2002

Operations by business segment for the years ended December 31, 2003 and 2002 follow:

	Restated (See Note 2)		
	Years Ended December 31,		
Contract Drilling	**2003**	**2002**	**% Change**
	(Dollars in thousands)		
Revenues	$ 639,694	$ 410,295	55.9%
Direct operating costs	$ 475,224	$ 318,201	49.3%
Selling, general and administrative	$ 4,401	$ 3,963	11.1%
Depreciation and amortization	$ 87,255	$ 82,102	6.3%
Operating income	$ 72,814	$ 6,029	1,107.7%
Operating days	68,798	45,919	49.8%
Average revenue per operating day	$ 9.30	$ 8.94	4.0%
Average direct operating costs per operating day	$ 6.91	$ 6.93	(0.3)%
Number of owned rigs at end of period	343	324	5.9%
Average number of rigs owned during period	336	323	4.0%
Average rigs operating	188	126	49.2%
Rig utilization percentage	56%	39%	43.6%
Capital expenditures	$ 77,350	$ 59,966	29.0%

The average market price of natural gas and our average rigs operating for each of the fiscal quarters in 2003 and 2002 follow:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2003:				
Average natural gas price	$ 5.91	$ 5.70	$ 4.88	$ 5.29
Average rigs operating	176	195	192	191
2002:				
Average natural gas price	$ 2.51	$ 3.41	$ 3.20	$ 4.31
Average rigs operating	117	119	127	140

The average market price of natural gas improved to $5.45 per Mcf in 2003 compared to $3.36 per Mcf in 2002, resulting in an increase in demand for our contract drilling services. Our average number of rigs operating increased to 188 in 2003 from 126 in 2002.

Revenues and direct operating costs increased as a result of the increased number of operating days in 2003. Revenue per operating day increased as a result of increased demand for our services which resulted in additional increases in revenues and operating income. As a result of the increased utilization of our drilling rigs in 2003, significant capital expenditures were incurred to modify and upgrade our existing drilling rigs and to acquire additional related equipment to meet the increased demand. Increased depreciation expense in 2003 resulted from this increased level of capital spending, as well as acquisitions.

	Years Ended December 31,		
Pressure Pumping	**2003**	**2002**	**% Change**
	(Dollars in thousands)		
Revenues	$ 46,083	$ 32,996	39.7%
Direct operating costs	$ 26,184	$ 19,802	32.2%
Selling, general and administrative	$ 5,683	$ 4,301	32.1%
Depreciation	$ 3,774	$ 2,803	34.6%
Operating income	$ 10,442	$ 6,090	71.5%
Total jobs	5,667	3,796	49.3%
Average revenue per job	$ 8.13	$ 8.69	(6.4)%
Average direct operating costs per job	$ 4.62	$ 5.22	(11.5)%
Capital expenditures	$ 10,524	$ 7,399	42.2%

The increases in revenues and expenses for our pressure pumping operations were attributable to improved industry conditions, as discussed in Contract Drilling above, and continued expansion of our pressure pumping services into the Appalachian regions of Kentucky and West Virginia. This expansion also resulted in increases in selling, general and administrative expenses and depreciation in 2003 compared to 2002.

	Restated (See Note 2)		
	Years Ended December 31,		
Drilling and Completion Fluids	**2003**	**2002**	**% Change**
	(Dollars in thousands)		
Revenues	$ 69,230	$ 69,943	(1.0)%
Direct operating costs	$ 61,424	$ 60,762	1.1%
Selling, general and administrative	$ 7,447	$ 7,243	2.8%
Depreciation and amortization	$ 2,279	$ 2,176	4.7%
Operating loss	$ 1,920	$ 238	706.7%
Total jobs	1,931	1,457	32.5%
Average revenue per job	$ 35.85	$ 48.00	(25.3)%
Average direct operating costs per job	$ 31.81	$ 41.70	(23.7)%
Capital expenditures	$ 912	$ 1,571	(41.9)%

The decrease in revenues was primarily due to the decrease in larger jobs completed in the Gulf of Mexico as activity in the Gulf of Mexico continued to be slow despite improved natural gas prices in 2003. The decrease in revenues from the Gulf of Mexico was largely offset by increased demand for our land-based drilling and completion fluids services. Land-based drilling and completion fluids jobs typically generate less revenue per job than offshore jobs. As a result, our average revenue per job decreased in 2003 compared to 2002.

	Years Ended December 31,		
Oil and Natural Gas Production and Exploration	**2003**	**2002**	**% Change**
	(Dollars in thousands)		
Revenues	$ 21,163	$ 14,723	43.7%
Direct operating costs	$ 4,808	$ 3,956	21.5%
Selling, general and administrative	$ 1,489	$ 1,571	(5.2)%
Depreciation, depletion and impairment	$ 7,082	$ 5,251	34.9%
Operating income	$ 7,784	$ 3,945	97.3%
Capital expenditures	$ 10,015	$ 6,357	57.5%
Average net daily oil production (Bbls)	788	794	(0.8)%
Average net daily gas production (Mcf)	5,656	5,109	10.7%
Average oil sales price (per Bbl)	$ 30.54	$ 25.02	22.1%
Average gas sales price (per Mcf)	$ 4.97	$ 2.91	70.8%

Increased revenues and operating income are primarily attributable to increased prices received from sales of oil and natural gas and increased production of natural gas in 2003. Depreciation and depletion expense primarily increased as a result of increased production of natural gas in 2003 as compared to 2002, as well as an increase of approximately $700,000 associated with expenses incurred to partially impair certain oil and natural gas properties.

	Restated (See Note 2)		
	Years Ended December 31,		
Corporate and Other	**2003**	**2002**	**% Change**
	(Dollars in thousands)		
Selling, general and administrative	$ 8,665	$ 9,038	(4.1)%
Bad debt expense	$ 259	$ 320	(19.1)%
Depreciation	$ 444	$ 446	(0.4)%
Gain on sale of assets	$ 1,927	$ 360	435.3%
Other	$ (2,452)	$ 4,700	N/A
Embezzled funds expense	$ 17,849	$ 8,574	108.2%
Interest income	$ 1,116	$ 1,110	0.5%
Interest expense	$ 292	$ 532	(45.1)%

In 2003, Other reflects a payment received in the first quarter of 2003 of approximately $2.5 million as settlement for contract drilling services previously provided in Mexico by Norton Drilling Company Mexico, Inc., a wholly-owned subsidiary. The underlying accounts receivable balance had been reserved as uncollectible at the time of our acquisition of Norton Drilling Company Mexico, Inc. in 1999. In 2002, Other reflects a $4.7 million charge due to the financial failure of a workers compensation insurance carrier we used from 1992 until March 2001. Embezzled funds expense includes fraudulent payments made to or for the benefit of Jonathan D. Nelson, our former CFO, for assets and services that were not received by the Company.

Income Taxes

	Restated (See Note 2)		
	Years Ended December 31,		
	2004	2003	2002
	(Dollars in thousands)		
Income (loss) before income tax	$ 149,147	$ 68,976	$ (6,089)
Income tax expense (benefit)	54,801	25,320	(1,949)
Effective tax rate	36.7%	36.7%	32.0%

Our effective income tax rate of 36.7% for 2004 and 2003 is primarily attributable to a Federal rate of 35.0% and state income tax rates of 1.6% and 1.5%, respectively. The impact of permanent differences was not significant in 2004 or 2003. The significance of the impact of the permanent differences of approximately (5)% to our effective income tax rate in 2002 was largely attributable to our reduced 2002 pretax earnings.

For tax purposes, we have available at December 31, 2004, Federal net operating loss carryforwards of approximately $16 million and $118,000 of alternative minimum tax credit carryforwards. These carryforwards are attributable to the acquisition of TMBR in February 2004.

The net operating loss carryforwards, if unused, are scheduled to expire as follows: 2005 $5 million, 2006 $1 million, 2011 $2 million, 2018 $4 million and 2019 $4 million. The alternative minimum tax credit may be carried forward indefinitely.

We record non-cash deferred Federal income taxes based primarily on the relationship between the amount of our unused Federal net operating loss carryforwards and the temporary differences between the book basis and tax basis in 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 incurred deferred income tax expense of approximately $14.8 million, $10.0 million and $19.6 million for 2004, 2003 and 2002, respectively.

Volatility of Oil and Natural Gas Prices

Our revenue, profitability and rate of growth are substantially dependent upon prevailing prices for oil and natural gas, with respect to all of our operating segments. For many years, oil and natural gas prices and markets have been 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. Natural gas prices fell from an average of $6.23 per Mcf in the first quarter of 2001 to an average of $2.51 per Mcf for the same period in 2002. During this same period, the average number of our rigs operating dropped by approximately 50%. The average market price of natural gas improved from $3.36 in 2002 to $5.45 in 2003 and $5.95 in 2004, resulting in an increase in demand for our drilling services. Our average number of rigs operating increased from 126 in 2002 to 188 in 2003 and 211 in 2004. We expect oil and natural gas prices to continue to be volatile and to affect our financial condition and operations and ability to access sources of capital.

The North American land drilling industry has experienced many downturns in demand over the last several years. 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.

Impact of Inflation

We believe that inflation will not have a significant near-term impact on our financial position.

Recently-Issued Accounting Standards

The Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard No. 123 (revised 2004), *Share-Based Payment (SFAS 123(R))* in December 2004; it replaces

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FASB Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation,* and supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*. This statement is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We will adopt SFAS 123(R) no later than our fiscal quarter beginning July 1, 2005.

We currently use the intrinsic value method to value stock options, and accordingly, no compensation expense has been recognized for stock options since we grant stock options with exercise prices equal to our common stock market price on the date of the grant. SFAS 123(R) requires the expensing of all stock-based compensation, including stock options and restricted shares, using the fair value method. We will expense stock options using the Modified Prospective Transition method as described in SFAS 123(R). This method requires expense to be recognized for new grants or modifications to existing grants issued in the period of adoption, plus the current period expense for non-vested awards issued prior to the adoption of SFAS 123(R). Compensation cost for the unvested stock-based awards will be recognized over the remaining vesting period. No expense will be recognized for stock options vested in periods prior to the adoption of SFAS 123(R).

We are evaluating the impact of the adoption of SFAS 123(R) on our results of operations and financial position. Adoption is not expected to have a material effect on our financial position or results of operations.

The FASB issued Statement of Financial Accounting Standard No. 151, *Inventory Costs an amendment of ARB No. 43, Chapter 4* (SFAS 151). SFAS 151 is effective, and will be adopted, for inventory costs incurred during fiscal years beginning after June 15, 2005 and is to be applied prospectively. SFAS 151 amends the guidance in ARB No. 43, Chapter 4, *Inventory Pricing,* to require current period recognition of abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Adoption is not expected to have a material effect on our financial position or results of operations.

The FASB issued Statement of Financial Accounting Standard No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29* (SFAS 153). FAS 153 is effective, and will be adopted, for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005 and is to be applied prospectively. SFAS 153 eliminates the exception for fair value treatment of nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. Adoption is not expected to have a material effect on our financial position or results of operations.

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

We currently have no exposure to interest rate market risk as we have no outstanding balance under our credit facility. Should we incur a balance in the future, we would have exposure associated with the floating rate of the interest charged on that balance. The revolving credit facility calls for periodic interest payments at a floating rate ranging from LIBOR plus 0.625% to 1.0% or at the prime rate. The applicable rate above LIBOR is based upon our debt to capitalization ratio. Our exposure to interest rate risk due to changes in LIBOR is not expected to be material.

We conduct some business in Canadian dollars through our Canadian land-based drilling operations. The exchange rate between Canadian dollars and U.S. dollars has fluctuated over 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 when they are translated to U.S. dollars. Also, the value of our Canadian net assets in U.S. dollars may decline.

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

Background to the Fraud and Restatement

In November 2005, the Company discovered that its former Chief Financial Officer, Jonathan D. Nelson (Nelson), had fraudulently diverted approximately $78 million in Company funds for his own benefit. Nelson s fraudulent diversions began in 1998 and continued until the fourth quarter of 2005 when he resigned from the Company. The funds fraudulently diverted were recorded as payments for assets or services that were not actually received by the Company.

Beginning in 1998, and continuing until late 2000, Nelson wrote a series of checks aggregating approximately $4.9 million to himself and to, or for the benefit of, a company owned and controlled by him. During this time, Nelson had check writing authority on the Company s principal funding account, and also had the ability to intercept bank statement information sent to the Company. When Nelson intercepted that information, he removed the cancelled checks reflecting the embezzled funds from the bank statements and then provided false information to other Company employees regarding those checks. Company employees used the false information Nelson provided in recording the transactions.

In 1999, Nelson gained access to a form authorizing his salary increase and improperly added a provision to it that created an additional expense allowance benefit of $2,000 per month, along with a provision making the salary increase and unauthorized expense allowance retroactive for several months. Nelson added these provisions himself and then forged the initials of the Company s Chief Executive Officer on the form as authorization for these non-approved payments.

Beginning in December 2000 and continuing until October 2005, Nelson caused the wiring of Company funds aggregating approximately $70.2 million to, or for the benefit of, entities owned and controlled by him. Nelson was originally able to initiate these wire transfers by requesting the wire transfers himself in telephone calls to one of the Company s banks. After changes to the Company s internal controls and procedures in 2004, Nelson initiated the wire transfers through instructions to one of his subordinates and by the creation of fraudulent invoices containing forged senior management approvals.

In connection with an acquisition by the Company in early 2004, Nelson also used a wire transfer to fraudulently divert funds from the Company. At the time of the acquisition, Nelson initiated a wire transfer for approximately $2.1 million by sending an email to one of his subordinates in which he falsely represented that the wired funds were to be used to pay off the seller s obligation for an aircraft maintenance agreement relating to the acquired business. In reality, Nelson used the funds to purchase an airplane for his personal use.

Finally, in October 2004, Nelson diverted Company funds of approximately $1.6 million to finance an investment in a company. Nelson accomplished the fraudulent diversion of Company funds by improperly directing the bank to fund Nelson s personal investment.

After Nelson resigned from the Company in November 2005, the Company became aware that Nelson had fraudulently diverted Company funds. As a result, the Audit Committee of the Board of Directors commenced an investigation into Nelson s activities. The Audit Committee retained independent counsel and independent forensic accountants to assist with the investigation.

The investigation confirmed the above facts and revealed that Nelson exploited the reliance placed on him to create an environment at the Company which discouraged routine communication concerning financial and business information within the organization between senior management (other than Nelson) and those employees engaged in the Company s financial reporting and accounting functions (other than Nelson). Nelson also discouraged communication between employees involved in financial reporting and accounting functions and those involved in operational activities. The control environment at the Company resulted in Company employees placing trust in Nelson and placed Nelson at the center of information flows about financial reporting and accounting matters.

The control environment allowed Nelson to override certain of the Company s internal controls and procedures, and contributed to the failure of Company employees charged with certain financial and accounting duties to exercise appropriate judgment, skepticism and objectivity, such that prevention or detection of the override of established policies, procedures, controls and Nelson s inappropriate transactions did not occur while Nelson was employed by the Company. This allowed Nelson to make unauthorized payments for assets that were not, in fact, ordered by or delivered to the Company, and for services that were not actually provided to the Company and to conceal the fraudulent transactions within the Company s accounting and financial records and reports.

On December 22, 2005, the Company announced that the Audit Committee of the Company had concluded that it was necessary to restate its previously reported financial statements for the years ended December 31, 2004, 2003 and 2002. In addition, the Company will restate its financial statements for the first three quarters of 2005 and all quarters in 2004 and 2003. As a result, the Audit Committee concluded that the Company s previously filed consolidated financial statements for the periods indicated above should no longer be relied upon. Restatement adjustments are further described in Note 2 of the Notes to the Consolidated Financial Statements.

Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and current Chief Financial Officer (CFO), we conducted an evaluation of the effectiveness of our disclosure controls and procedures, as such terms are defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities and Exchange Act of 1934, as amended (the Exchange Act), as of the end of the period covered by this Annual Report on Form 10-K/ A. Disclosure controls and procedures are designed to ensure that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized, and reported on a timely basis and that such information is accumulated and reported to management, including our CEO and CFO, as appropriate, to allow timely disclosures regarding required disclosures.

At the time of the filing of our Annual Report on Form 10-K for the year ended December 31, 2004, our CEO and former CFO concluded that our disclosure controls and procedures were effective as of December 31, 2004. Subsequent to that evaluation, our CEO and current CFO concluded that our disclosure controls and procedures were not effective at a reasonable level of assurance, as of December 31, 2004, because of the material weaknesses discussed below. Based upon the substantial work performed during the restatement process, management has concluded that the Company s consolidated financial statements for the periods covered by and included in this Annual Report on Form 10-K/ A are fairly stated in all material respects.

Management s Report on Internal Control Over Financial Reporting (Restated)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f). Our CEO and current CFO conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2004 using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework* (COSO framework). 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 policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Our current management identified the following material weaknesses in our internal control over financial reporting as of December 31, 2004:

1. Control environment. We did not maintain an effective control environment based on the criteria established in the COSO framework. Specifically, the Company did not maintain a control environment adequate to encourage the prevention or detection of the override of our controls or intentional misconduct, including misappropriation of assets and the preparation of false management reports, accounting records, financial statements and documents together with forged approval signatures. This lack of an effective control environment allowed our former CFO to take inappropriate actions that resulted in certain transactions not being properly reflected in our consolidated financial statements for the years ended December 31, 2004, 2003 and 2002, each of the quarters of 2004 and 2003, and the first three quarters of 2005. This intentional misconduct by our former CFO included the preparation of false accounting records and documents to deceive accounting personnel under his supervision, other members of senior management, our Board of Directors and our independent registered public accountants. Additionally, the lack of an effective control environment allowed our lines of communication among, and our monitoring of, our operations and accounting personnel, including our former CFO, to not be effective in preventing or detecting these instances of intentional misconduct. Taken as a whole, our control environment did not adequately emphasize appropriate judgment, skepticism and objectivity, and our former CFO intentionally exploited this environment for his personal benefit, specifically with respect to our controls over cash, payroll and property and equipment as follows:

a. Cash. Our former CFO manipulated the process over the initiation and approval of cash wire transfers. This action was taken in order to accomplish the fraudulent diversion of cash from the Company to entities owned by our former CFO for goods and services which the Company neither requested nor received. False documentation was created by our former CFO to conceal the true nature of these transactions from the Company and its independent registered public accountants.

b. Payroll. In 1999, our former CFO intentionally altered his payroll records to indicate that appropriate authorization had been given for a retroactive increase in his compensation and related benefits when in fact no such authorization had been provided. This false documentation was created by our former CFO to provide for an unauthorized increase to his compensation and to conceal the unauthorized compensation increase from the Company and its independent registered public accountants.

c. Property and Equipment. Our former CFO instructed certain former employees, who worked under his supervision, to alter management reports related to property and equipment expenditures. Additionally, our former CFO created fictitious property and equipment approval forms with forged signatures. These actions had the effect of concealing his inappropriate and fraudulent diversion of cash. The activities by our former CFO deceived the Company and its independent registered public accountants as to the true nature of the Company s cash transfers and property and equipment expenditures.

This control environment material weakness contributed to the embezzlement occurring, which in turn resulted in the restatement of our consolidated financial statements for the years ended December 31, 2004, 2003 and 2002, each of the quarters of 2004 and 2003, and the first three quarters of 2005. Additionally, this control environment material weakness could result in misstatements of any of our financial statement accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, our management has determined that this control deficiency constitutes a material weakness.

The material weakness in our control environment contributed to the existence of the following additional material weaknesses:

2. Controls over cash. We did not maintain effective controls to ensure cash disbursements only occurred based upon authorized Company transactions. Specifically, our former CFO was able to initiate electronic cash transfers without review, approval, or appropriate documentation. This allowed him to

fraudulently cause the Company to make disbursements through submission of fictitious supporting documents with forged executive signatures which appeared to evidence approval. This control deficiency contributed to the embezzlement which resulted in the restatement of our consolidated financial statements for the years ended December 31, 2004, 2003 and 2002, each of the quarters of 2004 and 2003, and the first three quarters of 2005. Additionally, this control deficiency could result in misstatements of our cash and related accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, our management has determined that this control deficiency constitutes a material weakness.

3. Controls over property and equipment. We did not maintain effective controls over the existence, completeness and accuracy of our accounting for property and equipment. Specifically, our controls were not adequate to ensure (i) that our property and equipment purchases by wire transfer, not processed through our vendor and accounts payable controls, were authorized or existed, which contributed to the concealment of the embezzlement, (ii) the timely and accurate depreciation of all property and equipment, (iii) the identification and recording of all property and equipment retirements when they occurred, and (iv) that property and equipment transferred between our locations was accurately and completely reflected in our accounting records. This control deficiency resulted in certain inaccuracies in our accounting for property and equipment and in the restatement of our consolidated financial statements for the years ended December 31, 2004, 2003 and 2002; each of the quarters of 2004 and 2003; and the first three quarters of 2005. Additionally, this control deficiency could result in a misstatement of our property and equipment and related depreciation expense accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, our management has determined that this control deficiency constitutes a material weakness.

In Management s Report on Internal Control Over Financial Reporting included in our original Annual Report on Form 10-K for the year ended December 31, 2004, our management, including our CEO and former CFO, concluded that we maintained effective internal control over financial reporting as of December 31, 2004. Our CEO and current CFO have subsequently concluded that the material weaknesses described above existed as of December 31, 2004. As a result, they now have concluded that we did not maintain effective internal control over financial reporting as of December 31, 2004, based on the criteria in *Internal Control-Integrated Framework* issued by the COSO. Accordingly, management has restated its report on internal control over financial reporting.

Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which begins on page F-2 of this Annual Report on Form 10-K/ A.

Changes in Internal Control Over Financial Reporting

Management is committed to remediating each of the material weaknesses identified above by implementing changes to the Company s internal control over financial reporting. Management has implemented, or is in the process of implementing, the following changes to the Company s internal control systems and procedures:

We have changed our wire transfer approval policies to require additional and more secure authorizations for wires to ensure that all wire transfers are to approved vendors, and to ensure that all such transactions are reflected in the Company s accounts payable system and have appropriate supporting documentation.

We have revised our approval for property and equipment expenditure requirements to provide for improved controls over the existence of fixed assets as well as the completeness and accuracy of our fixed asset records.

We are strengthening our tracking system for property and equipment to improve the tracking of those assets between our yards and rigs and to trigger the timely commencement of depreciation of assets placed in service.

We are implementing procedures and processes to reinforce with our employees their responsibilities to exercise independence and judgment and to comply with the Company s compliance programs, including:

- formal certifications of information contained in SEC filings relating to their areas of responsibility;
- annual written questionnaires from senior employees and accounting staff with respect to awareness as to questionable business practices;
- improved education and training programs for all employees covering ethics, compliance, financial reporting and good business practices;
- additional guidelines with respect to senior management s responsibilities for SEC filings, financial reports, budgets and maintenance of controls over assets and expenditures; and
- annual reporting to the Audit Committee with respect to these processes and procedures.

In addition, we will initiate a search for an in-house counsel whose responsibilities will include an active role in corporate compliance and governance.

We have initiated structural changes and processes and procedures to increase communications between the financial reporting and accounting functions and operations and between the financial reporting and accounting functions and senior management.

Additionally, management is committed to continued improvements in controls. In this regard, we are revising our internal audit reporting structure to further enhance its direct reporting to the audit committee and its program of monitoring controls.

Management is currently in the process of evaluating our internal control over financial reporting as of December 31, 2005 as prescribed by Section 404 of the Sarbanes-Oxley Act of 2002. The remediation efforts noted above are subject to the Company s internal controls assessment, testing and evaluation processes. We expect that our internal control over financial reporting will not be effective as of December 31, 2005. While these remediation efforts continue, we will rely on additional substantive procedures and other measures as needed to assist us in meeting the objectives otherwise fulfilled by an effective control environment.

Other than as described herein, 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. During the fourth quarter of 2005 we implemented our additional controls over wire transfers. The remaining remediation activities noted above were initiated in the fourth quarter of 2005 and the remaining controls will be implemented in 2006.

Item 9B. Other Information

On October 22, 2004, we entered into a written letter agreement with each of Mark S. Siegel, Kenneth N. Berns and John E. Vollmer III confirming and evidencing the existing agreement between us and each of Messrs. Siegel, Berns and Vollmer pursuant to which we have agreed to pay each such person within ten (10) days of the termination of his employment with us for any reason (including voluntary termination by them), an amount in cash equal to his annual base salary at the time of such termination. Any such payment made by us pursuant to the agreement evidenced in the letter agreement will reduce dollar for dollar any payment owed to such person, if any, pursuant to the Change in Control Agreement dated January 29, 2004 between the Company and such person or any agreement in substitution therefor.

PART III

The information required by Part III is omitted from this Report because we will file a definitive 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 and Executive Officers of the Registrant.***

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

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.***

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.

2.1	Asset Purchase Agreement among Key Energy Drilling, Inc., Key Energy Drilling Beneficial, L.P., Key Rocky Mountain, Inc., Key Four Corners, Inc. and Key Energy Services, Inc. and Patterson-UTI Drilling Company LP, LLLP and Patterson-UTI Energy, Inc., dated as of December 7, 2004.**
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	Amended and Restated Bylaws (filed March 19, 2002 as Exhibit 3.2 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2001 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 2.1, 4.1, 4.2 and 4.4.
10.2	Patterson-UTI Energy, Inc., 1993 Stock Incentive Plan, as amended (filed March 13, 1998 as Exhibit 10.1 to the Company s Registration Statement on Form S-8 (File No. 333-47917) and incorporated herein by reference).*

10.3	Patterson-UTI Energy, Inc. Non-Employee Directors Stock Option Plan, as amended (filed November 4, 1997 as Exhibit 10.1 to the Company s Registration Statement on Form S-8 (File No. 333-39471) and incorporated herein by reference).*
10.4	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).*
10.5	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).*

10.6	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).*
10.7	Amended and Restated Patterson-UTI Energy, Inc. Non-Employee Director Stock Option Plan(filed July 28, 2003 as Exhibit 4.8 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003 and incorporated herein by reference).*
10.8	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).*
10.9	1997 Stock Option Plan of DSI Industries, Inc. (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. 333-60470) and incorporated herein by reference).*
10.10	Stock Option Agreement dated July 20, 2001 between Patterson-UTI Energy, Inc. and Kenneth R. Peak (filed March 19, 2002 as Exhibit 10.9 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2001 and incorporated herein by reference).*
10.11	Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and Mark S. Siegel (filed August 9, 2004 as Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*
10.12	Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and Cloyce A. Talbott (filed August 9, 2004 as Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*
10.13	Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and A. Glenn Patterson (filed August 9, 2004 as Exhibit 10.3 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*
10.14	Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and Kenneth N. Berns (filed August 9, 2004 as Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*
10.15	Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and Jonathan D. Nelson (filed August 9, 2004 as Exhibit 10.5 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*

10.16	Restricted Stock Award Agreement dated April 28, 2004 between Patterson-UTI Energy, Inc. and John E. Vollmer III (filed August 9, 2004 as Exhibit 10.6 to the Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 and incorporated herein by reference).*
10.17	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).*
10.18	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and A. Glenn Patterson (filed on February 4, 2004 as Exhibit 10.3 to the Company s Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*
10.19	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Cloyce A. Talbott (filed on February 4, 2004 as Exhibit 10.4 to the Company s Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*
10.20	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).*
10.21	Patterson-UTI Energy, Inc. Change in Control Agreement, effective as of January 29, 2004, by and between Patterson-UTI Energy, Inc. and Jonathan D. Nelson (filed on February 4, 2004 as Exhibit 10.6 to the Company s Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).*

10.22	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).*
10.23	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.*/**
10.24	Form of Indemnification Agreement entered into by Patterson-UTI Energy, Inc. with each of Mark S. Siegel, Cloyce A. Talbott, A. Glenn Patterson, Kenneth N. Berns, Robert C. Gist, Curtis W. Huff, Terry H. Hunt, Kenneth R. Peak, Nadine C. Smith, Jonathan D. Nelson and John E. Vollmer III (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).*
10.25	Credit Agreement dated as of December 17, 2004 among Patterson-UTI Energy, Inc., as the Borrower, Bank of America, N.A., as administrative agent, L/ C Issuer and a Lender and the other lenders and agents party thereto (filed on December 23, 2004 as Exhibit 10.1 to the Company s Current Report on Form 8-K and incorporated herein by reference).
10.26	Summary Description of 2003 Cash Bonus Plan.*/**
10.27	Summary Description of Director Compensation.*/**
14.1	Patterson-UTI Energy, Inc. Code of Business Conduct and Ethics for Senior Financial Executives (filed as Exhibit 14.1 to the Company s Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).
21.1	Subsidiaries of the Registrant.**
23.2	Consent of Independent Petroleum Engineer M. Brian Wallace, P.E.**
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.

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

** Previously filed.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

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

We have completed an integrated audit of Patterson-UTI Energy, Inc. s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

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 at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 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. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Company restated its 2004, 2003 and 2002 consolidated financial statements.

Internal control over financial reporting

Also, we have audited management s assessment, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 9A, that Patterson-UTI Energy, Inc. did not maintain effective internal control over financial reporting as of December 31, 2004, because the Company did not maintain (1) an effective control environment, (2) effective controls over cash and (3) effective controls over property and equipment, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides 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.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. The following material weaknesses have been identified and included in management s assessment as of December 31, 2004.

1. *Control environment.* The Company did not maintain an effective control environment based on the criteria established in the COSO framework. Specifically, the Company did not maintain a control environment adequate to encourage the prevention or detection of the override of controls or intentional misconduct, including misappropriation of assets and the preparation of false management reports, accounting records, financial statements and documents together with forged approval signatures. This lack of an effective control environment allowed the Company s former CFO to take inappropriate actions that resulted in certain transactions not being properly reflected in the Company s consolidated financial statements for the years ended December 31, 2004, 2003 and 2002, each of the quarters of 2004 and 2003, and the first three quarters of 2005. This intentional misconduct by the Company s former CFO included the preparation of false accounting records and documents to deceive accounting personnel under his supervision, other members of senior management, the Board of Directors and us. Additionally, the lack of an effective control environment allowed the Company s lines of communication among, and their monitoring of, their operations and accounting personnel, including their former CFO, to not be effective in preventing or detecting these instances of intentional misconduct. Taken as a whole, the Company s control environment did not adequately emphasize appropriate judgment, skepticism and objectivity, and their former CFO intentionally exploited this environment for his personal benefit, specifically with respect to the Company s controls over cash, payroll and property and equipment as follows:

a. *Cash.* The Company s former CFO manipulated the process over the initiation and approval of cash wire transfers. This action was taken in order to accomplish the fraudulent diversion of cash from the Company to entities owned by their former CFO for goods and services which the Company neither requested nor received. False documentation was created by the Company s former CFO to conceal the true nature of these transactions from the Company and its independent registered public accountants.

b. Payroll. In 1999, the Company s former CFO intentionally altered his payroll records to indicate that appropriate authorization had been given for a retroactive increase in his compensation and related benefits when in fact no such authorization had been provided. This false documentation was created by the Company s former CFO to provide for an unauthorized increase to his compensation and to conceal the unauthorized compensation increase from the Company and its independent registered public accountants.

c. *Property and Equipment.* The Company s former CFO instructed certain former employees, who worked under his supervision, to alter management reports related to property and equipment expenditures. Additionally, the Company s former CFO created fictitious property and

equipment approval forms with forged signatures. These actions had the effect of concealing his inappropriate and fraudulent diversion of cash. The activities by the Company s former CFO deceived the Company and its independent registered public accountants as to the true nature of the Company s cash transfers and property and equipment expenditures.

The Company s material weakness in its control environment contributed to the existence of the following additional material weaknesses:

2. *Controls over cash.* The Company did not maintain effective controls to ensure cash disbursements only occurred based upon authorized Company transactions. Specifically, the Company s former CFO was able to initiate electronic cash transfers without review, approval, or appropriate documentation. This allowed him to fraudulently cause the Company to make disbursements through submission of fictitious supporting documents with forged executive signatures which appeared to evidence approval affecting cash and other financial statement accounts. This control deficiency contributed to the embezzlement.

3. *Controls over property and equipment.* The Company did not maintain effective controls over the existence, completeness and accuracy of their accounting for property and equipment. Specifically, the Company s controls were not adequate to ensure (i) that the Company s property and equipment purchases by wire transfer, not processed through their vendor and accounts payable controls, were authorized or existed, which contributed to the concealment of the embezzlement, (ii) the timely and accurate depreciation of all property and equipment, (iii) the identification and recording of all property and equipment retirements when they occurred, and (iv) that property and equipment transferred between Company locations was accurately and completely reflected in their accounting records. This control deficiency resulted in certain inaccuracies in the Company s accounting for property and equipment.

The control deficiencies described above resulted in the restatement of the Company s consolidated financial statements for the years ended December 31, 2004, 2003 and 2002, each of the quarters of 2004 and 2003, and the first three quarters of 2005. Additionally, each of the control deficiencies described above could result in a misstatement in the aforementioned accounts or disclosures that would result in a material misstatement in the Company s annual or interim consolidated financial statement that would not be prevented or detected. Accordingly, the Company s management has determined that each of these control deficiencies constitute material weaknesses.

These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2004 consolidated financial statements, and our opinion regarding the effectiveness of the Company s internal control over financial reporting does not affect our opinion on those consolidated financial statements.

Management and we previously concluded that the Company maintained effective internal control over financial reporting as of December 31, 2004. Management has subsequently determined that the material weaknesses described above existed as of December 31, 2004. Accordingly, Management s Report on Internal Control Over Financial Reporting has been restated and our opinion on internal control over financial reporting, as presented herein, is different from that expressed in our previous report.

In our opinion, management s assessment that Patterson-UTI Energy, Inc. did not maintain effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. Also, in our opinion, because of the effects of the material weaknesses described above on the achievement of the objectives of the control criteria, Patterson-UTI Energy, Inc. has not maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control Integrated Framework* issued by the COSO.

PricewaterhouseCoopers LLP
Houston, Texas

February 24, 2005, except for the restatement discussed in Note 2 to the consolidated financial statements and the matter discussed in the penultimate paragraph of Management s Report on Internal Control Over Financial Reporting, as to which the date is March 15, 2006

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	Restated (See Note 2)	
	December 31,	
	2004	2003
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 112,371	$ 100,483
Accounts receivable, net of allowance for doubtful accounts of $1,909 and $2,133 at December 31, 2004 and 2003, respectively	214,097	156,345
Federal and state income taxes receivable		11,453
Inventory	17,738	15,206
Deferred tax assets, net	15,991	16,449
Other	26,836	15,697
Total current assets	387,033	315,633
Property and equipment, at cost, net	765,019	650,398
Goodwill	99,056	51,033
Investment in equity securities		19,771
Other	5,677	2,686
Total assets	$ 1,256,785	$ 1,039,521
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 54,553	$ 41,093
Accrued revenue distributions	11,297	8,545
Other	2,309	6,743
Accrued Federal and state income taxes payable	4,231	
Accrued expenses	79,163	60,853
Total current liabilities	151,553	117,234
Deferred tax liabilities, net	140,475	128,651
Other	3,256	3,822
Total liabilities	295,284	249,707
Commitments and contingencies		
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 at December 31, 2004 and 200,000,000 shares at December 31, 2003 with 171,625,841 (affected by a two- for-one stock split) and 82,483,148 issued and 168,512,745 (affected by a two-for-one stock split) and 80,976,600 outstanding at December 31, 2004 and 2003, respectively	1,716	825
Additional paid-in capital	597,280	506,018
Deferred compensation	(5,420)	
Retained earnings	373,712	290,237
Accumulated other comprehensive income, net of tax	7,350	4,389
Treasury stock, at cost, 3,113,096 shares (affected by a two-for-one stock split) and 1,506,548 shares at December 31, 2004 and 2003, respectively	(13,137)	(11,655)
Total stockholders equity	961,501	789,814
Total liabilities and stockholders equity	$ 1,256,785	$ 1,039,521

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Restated (See Note 2)		
	Years Ended December 31,		
	2004	2003	2002
	(In thousands, except per share data)		
Operating revenues:			
Contract drilling	$ 809,691	$ 639,694	$ 410,295
Pressure pumping	66,654	46,083	32,996
Drilling and completion fluids	90,557	69,230	69,943
Oil and natural gas	33,867	21,163	14,723
	1,000,769	776,170	527,957
Operating costs and expenses:			
Contract drilling	556,869	475,224	318,201
Pressure pumping	37,561	26,184	19,802
Drilling and completion fluids	76,503	61,424	60,762
Oil and natural gas	7,978	4,808	3,956
Depreciation, depletion, amortization and impairment	122,800	100,834	92,778
Selling, general and administrative	31,983	27,685	26,116
Bad debt expense	897	259	320
Embezzled funds expense	19,122	17,849	8,574
Gain on sale of assets	(1,411)	(1,927)	(360)
Other		(2,452)	4,700
	852,302	709,888	534,849
Operating income (loss)	148,467	66,282	(6,892)
Other income (expense):			
Interest income	1,140	1,116	1,110
Interest expense	(695)	(292)	(532)
Other	235	1,870	225
	680	2,694	803
Income (loss) before income taxes and cumulative effect of change in accounting principle	149,147	68,976	(6,089)
Income tax expense (benefit):			
Current	39,952	15,324	(21,506)
Deferred	14,849	9,996	19,557

		54,801		25,320		(1,949)
Income (loss) before cumulative effect of change in accounting principle		94,346		43,656		(4,140)
Cumulative effect of change in accounting principle, net of related income tax benefit of approximately $287				(469)		
Net income (loss)	$	94,346	$	43,187	$	(4,140)
Net income (loss) per common share:						
Basic:						
Income (loss) before cumulative effect of change in accounting principle	$	0.57	$	0.27	$	(0.03)
Cumulative effect of change in accounting principle	$		$		$	
Net (loss) income	$	0.57	$	0.27	$	(0.03)
Diluted:						
Income (loss) before cumulative effect of change in accounting principle	$	0.56	$	0.27	$	(0.03)
Cumulative effect of change in accounting principle	$		$		$	
Net income (loss)	$	0.56	$	0.26	$	(0.03)
Weighted average number of common shares outstanding:						
Basic		166,258		161,272		157,410
Diluted		169,211		164,572		157,410

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					Accumulated Other Comprehensive		
	Number of Shares	Amount	Additional Paid-In Capital	Deferred Compensation	Retained Earnings	Income (Loss)	Treasury Stock	Total
					(In thousands)			
December 31, 2001, as previously reported	78,463	$ 784	$ 441,475	$	$ 258,834	$ (2,296)	$ (11,655)	$ 687,142
Adjustment for effects of embezzlement (net of applicable income tax benefit of $4,499) (See Note 2)					(7,373)			(7,373)
Other adjustments (net of applicable income tax benefit of $38) (See Note 2)					(271)	843		572
December 31, 2001, as restated	78,463	784	441,475		251,190	(1,453)	(11,655)	680,341
Issue common stock	650	7	16,933					16,940
Stock options & warrants exercised	2,464	25	15,714					15,739
Tax benefit from stock options exercised			15,079					15,079
Foreign currency translation (net of applicable income tax of $168)						289		289
Net loss, as restated (See Note 2)					(4,140)			(4,140)
December 31, 2002, as restated	81,577	816	489,201		247,050	(1,164)	(11,655)	724,248
Stock options & warrants exercised	906	9	10,277					10,286
Tax benefit from stock options			6,540					6,540

exercised								
Foreign currency translation (net of applicable income tax of $3,220)						5,553		5,553
Net income, as restated (See Note 2)					43,187			43,187
December 31, 2003, as restated	82,483	825	506,018		290,237	4,389	(11,655)	789,814
Issue common stock for acquisition	1,388	14	49,462					49,476
Issue restricted stock	189	2	6,640	(6,642)				
Amortize deferred compensation expense				1,222				1,222
Stock options & warrants exercised	2,580	25	24,494					24,519
Tax benefit from stock options exercised			10,666					10,666
Foreign currency translation (net of applicable income tax of $1,716)						2,961		2,961
Purchase of treasury stock							(1,482)	(1,482)
Pay cash dividend (See Note 12)					(10,021)			(10,021)
Two-for-one stock split (See Note 12)	84,986	850			(850)			
Net income, as restated (See Note 2)					94,346			94,346
December 31, 2004, as restated	171,626	$ 1,716	$ 597,280	$ (5,420)	$ 373,712	$ 7,350	$ (13,137)	$ 961,501

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN CASH FLOWS

	Restated (See Note 2)		
	Years Ended December 31,		
	2004	2003	2002
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 94,346	$ 43,187	$ (4,140)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	122,800	100,834	92,778
Provision for bad debts	897	259	320
Deferred income tax expense	14,849	9,996	19,557
Tax benefit related to exercise of stock options	10,666	6,540	15,079
Amortization of deferred compensation expense	1,222		
Gain on sale of assets	(1,411)	(1,927)	(360)
Cumulative effect of change in accounting principle, net of tax		(469)	
Changes in operating assets and liabilities, net of business acquired:			
Accounts receivable	(50,682)	(55,791)	34,565
Federal income taxes receivable	15,734	11,155	(22,844)
Inventory and other current assets	(13,556)	(8,984)	(222)
Accounts payable	12,861	12,322	(11,079)
Accrued expenses	1,555	22,814	(771)
Other liabilities	(6,090)	5,015	362
Net cash provided by operating activities	203,191	144,951	123,245
Cash flows from investing activities:			
Acquisitions, net of cash acquired	(30,387)	(40,832)	
Purchases of property and equipment	(174,589)	(98,801)	(75,293)
Proceeds from sales of property and equipment	3,303	4,548	1,813
Purchase of investment equity securities			(17,659)
Change in other assets	(1,766)	(1,693)	735
Net cash used in investing activities	(203,439)	(136,778)	(90,404)
Cash flows from financing activities:			
Purchase of treasury stock	(1,482)		
Dividends paid	(10,021)		
Line of credit issuance costs	(780)		
Proceeds from exercise of stock options and warrants	24,519	10,286	15,739
Net cash provided by financing activities	12,236	10,286	15,739

Effect of foreign exchange rate changes on cash	(100)	(130)	(10)
Net increase in cash and cash equivalents	11,888	18,329	48,570
Cash and cash equivalents at beginning of year	100,483	82,154	33,584
Cash and cash equivalents at end of year	$ 112,371	$ 100,483	$ 82,154
Supplemental disclosure of cash flow information:			
Net cash received (paid) during the year for:			
Interest	$ (245)	$ (292)	$ (532)
Income taxes	(12,500)	2,730	13,492

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN CASH FLOWS (Continued)

Non-cash investing and financing activities:

In February 2004, the Company completed its acquisition of TMBR/ Sharp Drilling, Inc. (TMBR) in which one of its wholly-owned subsidiaries acquired 100% of the remaining outstanding shares of TMBR for a net cash payment of $32.5 million ($40.4 million paid to TMBR shareholders less $7.9 million in cash acquired in the transaction) and the issuance of 2.78 million shares of the Company s common stock valued at $17.82 per share (adjusted to reflect the two-for-one stock split on June 30, 2004). The assets of TMBR included 18 land-based drilling rigs and related equipment, shop facilities, equipment yards and their oil and natural gas properties. The transaction was accounted for as a business combination and the purchase price was allocated among the assets acquired and liabilities assumed based on their estimated fair market values (see Note 3).

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO 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., together with 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, Louisiana, Mississippi, Colorado, Utah, Wyoming and Western Canada. As of December 31, 2004, the Company owned 361 drilling rigs. The Company provides pressure pumping services to oil and natural gas operators primarily in the Appalachian Basin. The Company provides drilling fluids, completion fluids and related services to oil and natural gas operators in Texas, Southeastern New Mexico, Oklahoma, the Gulf Coast region of Louisiana and the Gulf of Mexico. The Company is also engaged in the development, exploration, acquisition and production of oil and natural gas. The Company s oil and natural gas business operates primarily in producing regions of West Texas, South Texas, Southeastern New Mexico, Utah and Mississippi.

Embezzlement & Restatement The Company s former Chief Financial Officer (CFO), Jonathan D. Nelson (Nelson), perpetrated an embezzlement over a period of more than five years. The accompanying consolidated financial statements have been restated to reflect the effects of losses incurred as a result of the embezzlement in the periods of occurrence. Payments related to the embezzlement previously capitalized as property and equipment and goodwill acquired, and the related depreciation and other amounts expensed have been reversed from the Company s accounting records. Embezzled payments have been recognized as expense in the periods they were embezzled. The cumulative effects of the embezzlement prior to 2002, have been recognized as a reduction of retained earnings as of that date. The accompanying consolidated financial statements have also been restated for the effects of the correction of other errors that are immaterial both individually and in the aggregate (see Note 2).

Basis of presentation As a result of the Company increasing its ownership of TMBR from 19.5% to 100% in 2004, the consolidated financial statements of Patterson-UTI Energy, Inc. and its wholly-owned subsidiaries have been restated in accordance with the requirements of accounting for business combinations accounted for as a purchase, to provide for the retroactive application of the equity method of accounting for the Company s investment in TMBR (see Note 7).

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 their functional currency. The effects of exchange rate changes are reflected in accumulated other comprehensive income, which is a separate component of stockholders equity.

On April 28, 2004, the Company s Board of Directors authorized a two-for-one stock split in the form of a stock dividend which was distributed on June 30, 2004 to holders of record on June 14, 2004. At June 30, 2004, an adjustment was made to reclassify an amount from retained earnings to common stock to account for the par value of the common stock issued as a stock dividend. This adjustment had no overall effect on equity. The December 31, 2003 balance sheet was not restated as a result of this transaction; however, historical earnings per share amounts included in the Statements of Income and elsewhere in these financial statements have been restated as if the two-for-one stock split had occurred on January 1, 2002.

A summary of the significant accounting policies follows:

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

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, as described below. 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 out-of-pocket expenses as direct costs.

Accounts receivable Trade accounts receivable are recorded at the invoiced amount and do not bear interest. 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 determines the allowance based on historical write-off experience. The Company reviews the adequacy of its allowance for doubtful accounts monthly. 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 consist 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 defined below.

	Useful Lives
Drilling rigs and related equipment	2-15
Office furniture	3-10
Buildings	5-20
Automotive equipment	2-7
Other	3-7

Oil and natural gas properties 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 determinations are 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 the related reserve classification. If the reserve classification is uncertain 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,

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
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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 an 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 provided 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 determine 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. As such, the Company assess impairment of its goodwill annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. With respect to the Company s drilling and completion fluids business, the determination that no impairment existed as of December 31, 2004, was based on the segment s improved operating results in 2004 and on the Company s expectations that these improved results will continue. If the improved results do not continue, all or part of the goodwill of approximately $10 million associated with that business segment may be determined to be impaired.

The following table summarizes depreciation, depletion, amortization and impairment expense for 2004, 2003 and 2002 (in millions):

		Restated (See Note 2)	
	2004	**2003**	**2002**
Depreciation expense	$ 109.4	$ 93.7	$ 87.4
Depletion expense	10.1	5.6	4.4
Amortization expense	0.1	0.1	0.3
Impairment of oil and natural gas properties	3.2	1.4	0.7
Total	$ 122.8	$ 100.8	$ 92.8

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.

Retirements Upon disposition or retirement of property and equipment, the cost and related accumulated depreciation are removed and any resulting gain or loss is credited or charged to operations.

Investments in equity securities Investments in equity securities are accounted for under the equity method of accounting.

Earnings per share The Company provides a dual presentation of its earnings per share; Basic Earnings per Share (Basic EPS) and Diluted Earnings per Share (Diluted EPS). Basic EPS is computed using the weighted average number of shares outstanding during the year. Diluted EPS includes common stock equivalents which are dilutive to earnings per share. For the years ended December 31, 2004 and 2003, dilutive securities, consisting of certain stock options and warrants, (See Note 13) included in the calculation of Diluted EPS were 3.0 million shares and 3.3 million shares, respectively. For the year ended December 31, 2002, dilutive securities of approximately 5.1 million shares were excluded from the calculation of Diluted EPS as a result of the Company s net loss (as restated) for that year. At December 31, 2004, 2003 and 2002, there were potentially dilutive securities of 640,000, 1.9 million and 657,000, respectively, excluded from the calculation of Diluted EPS as their exercise prices were greater than the average market price for the respective year.

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Stock based compensation At December 31, 2004, the Company had seven stock-based employee compensation plans, of which three were active. The Company accounts for those plans under the recognition and measurement principles of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, (APB 25) and related interpretations. During the second quarter of 2004, the Company granted restricted shares of the Company s common stock (the Restricted Shares) to certain key employees under the Patterson-UTI Energy, Inc. 1997 Long-Term Incentive Plan, as amended. As required by APB 25, the Restricted Shares were valued based upon the market price of the Company s common stock on the date of the grant. The resulting value is being amortized over the vesting period of the stock. Compensation expense of $773,000, net of tax, was included in net income for the twelve months ended December 31, 2004. Other than the Restricted Shares discussed above, no additional stock-based employee compensation cost is reflected in net income, as all options granted under the plans discussed above had an exercise price equal to or in excess of the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and net income per share if the Company had applied the fair value recognition provisions of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation, (SFAS 123) to stock-based employee compensation (in thousands, except per share amounts):

	Restated (See Note 2)		
	Years Ended December 31,		
	2004	**2003**	**2002**
Net income (loss), as reported	$ 94,346	$ 43,187	$ (4,140)
Add: Stock-based employee compensation expense recorded, net of tax	773		
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects(1)	(12,304)	(10,506)	(5,296)
Pro forma net income (loss)	$ 82,815	$ 32,681	$ (9,436)
Earnings (loss) per share:			
Basic, as reported	$ 0.57	$ 0.27	$ (0.03)
Basic, pro forma	$ 0.50	$ 0.20	$ (0.06)
Diluted, as reported	$ 0.56	$ 0.26	$ (0.03)
Diluted, pro forma	$ 0.50	$ 0.20	$ (0.06)
Weighted-average fair value per share of options granted(1)	$ 6.25	$ 5.59	$ 7.60

(1) See Note 13 for additional information regarding the computations presented here.

Statement of cash flows For purposes of reporting cash flows, cash and cash equivalents include cash on deposit, money market funds and investment grade municipal and commercial bonds with original maturities of 90 days or less.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Recently Issued Accounting Standards The FASB issued Statement of Financial Accounting Standard No. 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)) in December 2004; it replaces SFAS 123, and supersedes APB 25. The Company will adopt SFAS 123(R) no later than its fiscal quarter beginning July 1, 2005.

The Company currently uses the intrinsic value method to value stock options, and accordingly, no compensation expense has been recognized for stock options since the Company grants stock options with exercise prices equal to the Company s common stock market price on the date of the grant. SFAS 123(R) requires the expensing of all stock-based compensation, including stock options and restricted shares, using the fair value method. The Company will expense stock options using the Modified Prospective Transition method as described in SFAS 123(R). This method requires expense to be recognized for new grants or modifications to existing grants issued in the period of adoption, plus the current period expense for non-vested awards issued prior to the adoption of SFAS 123(R). Compensation cost for the unvested stock-based awards will be recognized over the remaining vesting period. No expense will be recognized for stock options vested in periods prior to the adoption of SFAS 123(R).

The Company is evaluating the impact of its adoption of SFAS 123(R) on its results of operations and financial position. Adoption is not expected to have a material effect on the Company s financial position or results of operations.

The FASB issued Statement of Financial Accounting Standard No. 151, *Inventory Costs an amendment of ARB No. 43, Chapter 4* (SFAS 151). SFAS 151 is effective, and will be adopted, for inventory costs incurred during fiscal years beginning after June 15, 2005 and is to be applied prospectively. SFAS 151 amends the guidance in ARB No. 43, Chapter 4, *Inventory Pricing,* to require current period recognition of abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage). Adoption is not expected to have a material effect on the Company s financial position or results of operations.

The FASB issued Statement of Financial Accounting Standard No. 153, *Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29* (SFAS 153). SFAS 153 is effective, and will be adopted, for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005 and is to be applied prospectively. SFAS 153 eliminates the exception for fair value treatment of nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. Adoption is not expected to have a material effect on the Company s financial position or results of operations.

Reclassifications Certain reclassifications have been made to the 2003 and 2002 consolidated financial statements in order for them to conform with the 2004 presentation.

2. Embezzlement and Restatements

On November 3, 2005, the Company announced the resignation of its CFO, Jonathan D. Nelson. On November 10, 2005, the Company announced that, based on information received by Company senior management on November 9, 2005, the Audit Committee of the Company s Board of Directors began an investigation into an embezzlement from the Company by Nelson.

Most of the embezzled funds result from Nelson causing the wiring of Company funds aggregating approximately $72.3 million, to, or for the benefit of, entities owned and controlled by him. Nelson was originally able to initiate these wire transfers by requesting the wire transfers himself in telephone calls to one of the Company s banks. After changes to the Company s internal controls and procedures in 2004, Nelson initiated the wire transfers through instructions to one of his subordinates and by the creation of fraudulent invoices containing forged senior management approvals. This false documentation was created by our former

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CFO to conceal the true nature of these transactions from the Company and its independent registered public accountants.

Nelson also instructed certain former employees, who worked under his supervision, to alter management reports related to property and equipment expenditures and created fictitious property and equipment approval forms with forged signatures.

On December 22, 2005, upon recommendation of Company management and the Audit Committee of its Board of Directors, the Company announced that based on the results to date of its ongoing internal investigation into the facts and circumstances surrounding the embezzlement by Nelson, the Company would restate its previously issued financial statements and amend its previously issued Annual Report on Form 10-K for the year ended December 31, 2004 and Quarterly Reports on Form 10-Q for the periods ended March 31, June 30 and September 30, 2005. These restatements reflect losses incurred as a result of payments made to or for the benefit of Nelson that had been recognized in the Company s accounting records and previously issued financial statements as payments for assets and services that were not received by the Company.

The total amount embezzled was approximately $77.5 million in cash, excluding any tax effects, beginning with the year ended December 31, 1998 through November 3, 2005 as follows (in thousands):

From 1998 to December 31, 2004	$	58,961
From January 1, 2005 to September 30, 2005		12,193
Total through September 30, 2005		71,154
From October 1, 2005 to November 3, 2005 (net of $1,500 repayment)		6,350
Total embezzlement	$	77,504

The Company promptly advised the United States Securities and Exchange Commission (SEC) when it became aware of the embezzlement. The SEC promptly obtained a freeze order on Nelson s assets (including assets held by entities controlled by him) and a Receiver was appointed to collect those assets. The United States attorney for the Northern District of Texas obtained an indictment against Nelson and investigation of this matter continues.

The Company understands that the Receiver will ultimately liquidate the assets and propose a plan to distribute the proceeds. While the Company believes it has a claim for at least the full amount embezzled, other creditors have or may assert claims on the assets held by the Receiver. As a result, recovery by the Company from the Receiver is uncertain as to timing and amount, if any. Recoveries, if any, will be recognized when they are considered collectable.

The accompanying consolidated financial statements have been restated to provide for, net of related tax effects, (1) the effects of losses incurred as a result of the former CFO s embezzlement and (2) the effects of the correction of other errors that are immaterial both individually and in the aggregate. These other adjustments relate primarily to the correction of previously reported property and equipment balances that result from our review of the Company s property and equipment records and the underlying physical assets in

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

connection with the investigation of the embezzlement. The effects of the embezzlement and other adjustments on the Company s financial position follow:

	As of December 31,			
	Previously Reported	Effects of Adjustment for Embezzlement	Effects of Other Adjustments	Restated
	(In thousands)			
2004:				
Property & equipment:				
At cost	$ 1,400,848	$ (55,211)	$ (6,866)	$ 1,338,771
Accumulated depreciation	(571,973)	1,348	(3,127)	(573,752)
Net	828,875	(53,863)	(9,993)	765,019
Goodwill	101,326	(2,270)		99,056
Total assets	1,322,911	(56,133)	(9,993)	1,256,785
Federal & state income taxes payable	2,754	1,311	166	4,231
Deferred tax liabilities, net	162,040	(22,159)	594	140,475
Liabilities	315,372	(20,848)	760	295,284
Retained earnings	415,489	(35,285)	(6,492)	373,712
Accumulated other comprehensive income	11,611		(4,261)	7,350
Stockholders equity	1,007,539	(35,285)	(10,753)	961,501
2003:				
Federal & state income taxes receivable	$ 12,667	$ (1,044)	$ (170)	$ 11,453
Property & equipment:				
At cost	1,161,536	(38,240)	(4,992)	1,118,304
Accumulated depreciation	(467,905)	890	(891)	(467,906)
Net	693,631	(37,350)	(5,883)	650,398
Goodwill	51,179	(146)		51,033
Total assets	1,084,114	(38,540)	(6,053)	1,039,521
Deferred tax liabilities, net	143,309	(15,044)	386	128,651
Liabilities	264,365	(15,044)	386	249,707
Retained earnings	317,627	(23,496)	(3,894)	290,237
Accumulated other comprehensive income	6,934		(2,545)	4,389
Stockholders equity	819,749	(23,496)	(6,439)	789,814

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The effects of the embezzlement and other adjustments on the Company s results of operations and cash flows follow:

	Year Ended December 31,			
	Previously Reported	Effects of Adjustment for Embezzlement	Effects of Other Adjustments	Restated
	(In thousands, except per share amounts)			
2004:				
Depreciation, depletion, amortization and impairment	$ 119,395	$ (461)	$ 3,866	$ 122,800
Selling, general and administrative	32,007	(24)		31,983
Gain on sale of assets	1,655		(244)	1,411
Embezzled funds expense		19,122		19,122
Operating income	171,214	(18,637)	(4,110)	148,467
Income before income taxes	171,894	(18,637)	(4,110)	149,147
Income tax expense	63,161	(6,848)	(1,512)	54,801
Net income	108,733	(11,789)	(2,598)	94,346
Per common share:				
Basic	0.65	(0.07)	(0.02)	0.57
Diluted	0.64	(0.07)	(0.02)	0.56
Net cash provided by (used in):				
Operating activities	222,289	(19,098)		203,191
Investing activities	(222,537)	19,098		(203,439)
Cash paid for:				
Acquisitions	32,514	(2,127)		30,387
Property & equipment	191,560	(16,971)		174,589
2003:				
Depreciation, depletion, amortization and impairment	$ 97,998	$ (450)	$ 3,286	$ 100,834
Selling, general and administrative	27,709	(24)		27,685
Gain on sale of assets	2,174		(247)	1,927
Embezzled funds expense		17,849		17,849
Operating income	87,190	(17,375)	(3,533)	66,282
Income before income taxes and cumulative effect of change in accounting principle	89,884	(17,375)	(3,533)	68,976
Income tax expense	32,996	(6,378)	(1,298)	25,320
Income before cumulative effect of change in accounting principle	56,888	(10,997)	(2,235)	43,656
Net income	56,419	(10,997)	(2,235)	43,187

Per common share:				
Basic	0.35	(0.07)	(0.01)	0.27
Diluted	0.34	(0.07)	(0.01)	0.26
Net cash provided by (used in):				
Operating activities	162,776	(17,825)		144,951
Investing activities	(154,603)	17,825		(136,778)

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
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	Year Ended December 31,			
	Previously Reported	Effects of Adjustment for Embezzlement	Effects of Other Adjustments	Restated
	(In thousands, except per share amounts)			
Cash paid for:				
Property & equipment	116,626	(17,825)		98,801
2002:				
Depreciation, depletion, amortization and impairment	$ 91,216	$ (301)	$ 1,863	$ 92,778
Selling, general and administrative	26,140	(24)		26,116
Gain on sale of assets	538		(178)	360
Embezzled funds expense		8,574		8,574
Operating income (loss)	3,398	(8,249)	(2,041)	(6,892)
Income (loss) before income taxes	4,201	(8,249)	(2,041)	(6,089)
Income tax expense (benefit)	1,827	(3,123)	(653)	(1,949)
Net income (loss)	2,374	(5,126)	(1,388)	(4,140)
Per common share:				
Basic	0.02	(0.03)	(0.01)	(0.03)
Diluted	0.01	(0.03)	(0.01)	(0.03)
Net cash provided by (used in):				
Operating activities	131,795	(8,550)		123,245
Investing activities	(98,954)	8,550		(90,404)
Cash paid for:				
Property & equipment	83,843	(8,550)		75,293

3. Acquisitions

Key Energy Services, Inc. In December 2004, the Company entered into an agreement to acquire the U.S. land-based drilling assets of Key Energy Services, Inc. for approximately $62 million. The assets include 25 active and 10 stacked drilling rigs, related drilling equipment, four yard facilities and a rig moving fleet consisting of approximately 45 trucks and 100 trailers. This transaction was completed in January 2005 using approximately $62 million of cash.

2004 Acquisition

TMBR/ Sharp Drilling, Inc. On February 11, 2004, the Company completed its acquisition of TMBR, a Texas corporation, in which one of its wholly-owned subsidiaries acquired 100% of the remaining outstanding shares of TMBR. Operations of TMBR subsequent to February 11, 2004, are included in the Company s consolidated financial statements. The transaction was accounted for as a business combination and the purchase price was allocated among the assets acquired and liabilities assumed based on their estimated fair market values. The assets of TMBR included 18 land-based drilling rigs and related equipment, shop facilities, equipment yards and their oil and natural gas properties.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The purchase price was calculated as follows (restated (See Note 2), in thousands, except per share data and exchange ratio):

Cash of $9.09 per share for the 4,447 TMBR shares outstanding at February 11, 2004, excluding the 1,059 TMBR shares owned by Patterson-UTI	$	40,423
Patterson-UTI shares issued at $17.82 per share (4,447 TMBR shares X .624332 exchange ratio X $17.82)		49,476
1,059 TMBR shares previously acquired by the Company		19,771
Acquisition costs		10,511
Less: Cash acquired		(7,909)
Total purchase price	$	112,272

The purchase price was allocated among assets acquired and liabilities assumed based on their estimated fair market values as follows (restated (See Note 2), in thousands):

Current assets	$	7,181
Fixed assets		60,784
Other long term assets		172
Deferred tax assets		13,080
Goodwill		48,020
Current liabilities		(7,080)
Other long term liabilities		(1,090)
Deferred tax liability		(8,795)
Total purchase allocation	$	112,272

The Company acquired TMBR to increase its productive asset base in the Permian Basin, which is one of the most active land drilling regions in the U.S. TMBR was well established in the contract drilling industry and maintained favorable customer relationships. Goodwill was recognized in the transaction as a result of these factors.

The following represents pro-forma unaudited financial information as if the acquisition had been completed on January 1, 2003 (in thousands, except per share amounts):

	Restated (See Note 2)			
		2004		**2003**
Revenue	$	1,005,357	$	818,774
Income before cumulative effect of change in accounting principle		94,047		45,430
Net income		94,047		44,961
Earnings per share:				
Basic	$	0.57	$	0.28
Diluted	$	0.56	$	0.27

2003 Acquisitions

SEI Drilling Company On January 31, 2003, the Company acquired four land-based drilling rigs and related equipment from SEI Drilling Company for $6.0 million in cash. The transaction was accounted for as

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

an acquisition of assets and the purchase price was allocated among the assets acquired based on their estimated fair market values.

Mesa Drilling, Inc. On February 7, 2003, the Company acquired three land-based drilling rigs, a yard and other related equipment from Mesa Drilling, Inc. and related entities for $10.5 million in cash. 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.

Other On April 28, 2003, the Company acquired two land-based drilling rigs for $3.9 million in cash. 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.

Hexadyne Drilling Corporation On May 30, 2003, the Company acquired seven land-based drilling rigs and related equipment from Hexadyne Drilling Corporation for $10.1 million in cash. 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.

Fort Drilling LLC On November 17, 2003, the Company acquired three land-based drilling rigs, a shop facility and related equipment from Fort Drilling LLC for $7.2 million in cash. 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.

Other In addition to the above mentioned acquisitions, the Company spent approximately $3.1 million on other acquisitions of assets and costs associated with the acquisitions completed during 2003.

2002 Acquisition

Odin Drilling, Inc. On March 21, 2002, the Company acquired five SCR electric land-based drilling rigs through the acquisition of Odin Drilling, Inc., for a purchase price of $16.9 million. The purchase price consisted of 1.3 million shares of common stock valued at $13.03 per share (adjusted to reflect the two-for-one stock split on June 30, 2004). A deferred tax liability of $4.1 million was recorded as a result of the transaction. 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. Comprehensive Income

The following table illustrates the Company s comprehensive income including the effects of foreign currency translation adjustments for the years ended December 31, 2004, 2003 and 2002 (in thousands):

	Restated (See Note 2)		
	2004	**2003**	**2002**
Net income (loss)	$ 94,346	$ 43,187	$ (4,140)
Other comprehensive income:			
Foreign currency translation adjustment related to Canadian operations, net of tax	2,961	5,553	289
Comprehensive income (loss)	$ 97,307	$ 48,740	$ (3,851)

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Property and Equipment

Property and equipment consisted of the following at December 31, 2004 and 2003 (in thousands):

	Restated (See Note 2)	
	2004	2003
Equipment	$ 1,239,519	$ 1,045,638
Oil and natural gas properties	82,711	57,625
Buildings	12,892	11,657
Land	3,649	3,384
	1,338,771	1,118,304
Less accumulated depreciation and depletion	(573,752)	(467,906)
	$ 765,019	$ 650,398

6. Goodwill

Goodwill is evaluated to determine if the fair value of the asset has decreased below its carrying value. At December 31, 2004 the Company performed its annual goodwill evaluation and determined no adjustment to impair goodwill was necessary. With respect to the Company s drilling and completion fluids business, the determination that no impairment existed as of December 31, 2004 was based on the segment s improved operating results in 2004 and on the Company s expectations that these improved results will continue. If the improved results do not continue, all or part of the goodwill of approximately $10 million associated with that business segment may be determined to be impaired. Goodwill as of December 31, 2004 and 2003 are as follows (in thousands):

	Restated (See Note 2)	
	2004	2003
Drilling:		
Goodwill at beginning of period	$ 41,069	$ 41,069
Goodwill in TMBR	48,020	
Other	3	
Goodwill at end of period	89,092	41,069
Drilling and completion fluids:		
Goodwill at beginning of period	9,964	9,964
Changes to goodwill		
Goodwill at end of period	9,964	9,964
Total goodwill	$ 99,056	$ 51,033

7. Investment in Equity Securities

As a result of the Company increasing its ownership of TMBR from 19.5% to 100% in 2004, the Company s consolidated financial statements for 2003 and 2002 were previously restated to provide for the retroactive application of the equity method of accounting for the investment in TMBR.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables present the effects of all restatements as of December 31, 2003 and for the years ended December 31, 2003 and 2002 (in thousands, except per share amounts):

	Previously Reported on Cost Basis	Effects of Adjustment to Equity Method	Effects of Adjustment for Embezzlement	Effects of Other Adjustments	Restated
As of December 31, 2003:					
Investment in equity securities	$ 20,274	$ (503)	$	$	$ 19,771
Deferred tax liability	$ 143,490	$ (181)	$ (15,044)	$ 386	$ 128,651
Retained earnings	$ 316,329	$ 1,298	$ (23,496)	$ (3,894)	$ 290,237
Accumulated other comprehensive income, net of tax	$ 8,554	$ (1,620)	$	$ (2,545)	$ 4,389
Year ended December 31, 2003:					
Other income	$ 143	$ 1,727	$	$	$ 1,870
Deferred income tax expense	$ 17,274	$ 634	$ (6,615)	$ (1,297)	$ 9,996
Net income	$ 55,326	$ 1,093	$ (10,997)	$ (2,235)	$ 43,187
Comprehensive income, net of tax	$ 65,689	$ (497)	$ (10,997)	$ (5,455)	$ 48,740
Net income per common share:					
Basic	$ 0.34	$ 0.01	$ (0.07)	$ (0.01)	$ 0.27
Diluted	$ 0.34	$ 0.01	$ (0.07)	$ (0.01)	$ 0.26
Year ended December 31, 2002:					
Other income (loss)	$ (137)	$ 362	$	$	$ 225
Deferred income tax expense	$ 23,548	$ 157	$ (3,399)	$ (749)	$ 19,557
Net income (loss)	$ 2,169	$ 205	$ (5,126)	$ (1,388)	$ (4,140)
Comprehensive income (loss), net of tax	$ 2,656	$ 175	$ (5,126)	$ (1,556)	$ (3,851)
Net income (loss) per common share:					
Basic	$ 0.01	$ 0.01	$ (0.03)	$ (0.01)	$ (0.03)
Diluted	$ 0.01	$ 0.00	$ (0.03)	$ (0.01)	$ (0.03)

8. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2004 and 2003 (in thousands):

	2004	2003

Salaries, wages, payroll taxes and benefits	$ 21,245	$ 15,772
Workers compensation liability	38,677	31,646
Sales, use and other taxes	5,863	5,809
Insurance, other than workers compensation	7,061	1,848
Other	6,317	5,778
	$ 79,163	$ 60,853

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Asset Retirement Obligation

Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, (SFAS 143), requires that the Company record a liability for the estimated costs to be incurred in connection with the abandonment of oil and natural gas properties in the future. The Company recorded a liability of approximately $1.1 million in the first quarter of 2003 upon initial adoption of SFAS 143. The following table describes the changes to the Company s asset retirement obligations during 2004 and 2003 (in thousands):

	2004	2003
Balance at beginning of year	$ 1,163	$ 1,056
Liabilities incurred*	1,277	173
Liabilities settled	(153)	(100)
Accretion expense	71	34
Asset retirement obligation at end of year	$ 2,358	$ 1,163

* The 2004 amount includes $1,091 of liabilities assumed in the acquisition of TMBR.

Had SFAS 143 been in effect as of January 1, 2001, the impact on the Company s results of operations would have been immaterial for the year ended December 31, 2002, and the asset retirement obligation would have been $1.1 million and $1.0 million as of December 31, 2002 and 2001, respectively. In addition, the cumulative effect of this change in accounting principle of approximately $469,000, net of tax, was recorded in the first quarter of 2003.

10. Notes Payable

The Company replaced its prior credit facility in December 2004 with a five-year, $200 million unsecured revolving line of credit (LOC). Interest is to be paid on outstanding LOC balances at a floating rate ranging from LIBOR plus 0.625% to 1.0% or the prime rate. This arrangement includes various fees, including a commitment fee on the average daily unused amount (0.15% at December 31, 2004). There are customary restrictions and covenants associated with the LOC. Financial covenants provide for a maximum debt to capitalization ratio and a minimum interest coverage ratio. The Company does not expect that the restrictions and covenants will restrict its ability to operate or react to opportunities that might arise. Availability under the LOC is reduced by outstanding letters of credit which totaled $49 million at December 31, 2004. There were no outstanding borrowings under the LOC at December 31, 2004. Costs of approximately $445,000 were expensed in 2004 to terminate the previous $100 million credit facility.

11. Commitments, Contingencies and Other Matters

The Company maintains letters of credit in the aggregate amount of $49.0 million for the benefit of various insurance companies as collateral for retrospective premiums and retained losses which may become payable under the terms of the underlying insurance contracts. These letters of credit expire variously during each calendar year. No amounts have been drawn under the letters of credit.

Contingencies The Company s contract services and oil and natural gas exploration and production operations are subject to inherent risks, including blowouts, 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 $2.0 million per occurrence with $4.0 million of aggregate coverage and excess liability and umbrella

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

coverages up to $50.0 million per occurrence and in the aggregate. The Company maintains a $1.0 million per occurrence deductible on its workers compensation insurance and its general liability insurance coverages. These levels of self-insurance expose the Company to increased operating costs and risks.

Net income for the year ended December 31, 2002 includes a charge of $4.7 million related to the financial failure in 2002 of a workers compensation insurance carrier that had provided coverage for the Company in prior years.

The Company believes it is adequately insured for public liability 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 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 carry insurance against loss of earnings resulting from such damage or loss.

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.

Other Matters Effective January 29, 2004, the Company entered into Change in Control Agreements with its Chairman of the Board, Chief Executive Officer, President and Chief Operating Officer, two Senior Vice Presidents and Chief Financial Officer (the Key Employees). Each Change in Control Agreement generally has a three-year 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 be entitled to, among other things,

- 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, Chief Executive Officer and President and Chief Operating Officer) or 1.5 times (in the case of the Senior Vice Presidents and the Chief Financial Officer) 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, Chief Executive Officer and President and Chief Operating Officer) or two years (in the case of the Senior Vice Presidents and the Chief Financial Officer).

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.

12. Stockholders Equity

On June 7, 2004, the Company s Board of Directors authorized a stock buyback program for the purchase of up to $30 million of outstanding shares of the Company s common stock. During the second quarter of 2004, the Company purchased 100,000 shares of its common stock in the open market for approximately $1.5 million (adjusted to reflect the two-for-one stock split on June 30, 2004). These shares are included in treasury stock at December 31, 2004.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During the second quarter of 2004, the Company granted Restricted Shares to certain key employees under the Patterson-UTI Energy, Inc. 1997 Long-Term Incentive Plan, as amended. As required by APB 25, the Restricted Shares were valued based upon the market price of the Company s common stock on the date of the grant. The resulting value is being amortized over the vesting period of the stock. Compensation expense of approximately $773,000, net of tax, was included in net income for the year ended December 31, 2004.

On April 28, 2004, the Company s Board of Directors authorized a two-for-one stock split in the form of a stock dividend which was distributed on June 30, 2004 to holders of record on June 14, 2004. In connection with the two-for-one stock split, an adjustment was made to reclassify an amount from retained earnings to common stock to account for the par value of the common stock issued as a stock dividend. This adjustment had no overall effect on equity. The prior year balance sheet was not restated as a result of this transaction; however, historical earnings per share amounts included in the Consolidated Statements of Income and elsewhere in this Report have been restated as if the two-for-one stock split had occurred on January 1, 2002.

On April 28, 2004, the Company s Board of Directors approved the initiation of a quarterly cash dividend of $0.02 on each share of its common stock which was paid on June 2, 2004. Quarterly dividends in the amount of $0.02 per share were also paid on September 1, 2004 and December 1, 2004. Total dividends paid in 2004 were approximately $10 million. In February 2005, the Company s Board of Directors approved an increase in the quarterly cash dividend on the Company s common stock to $0.04 per share from $0.02 per share. The next quarterly cash dividend is to be paid to holders of record on February 28, 2005 and paid on March 4, 2005. The amount and timing of all future dividend payments 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.

In February 2004, the Company completed its acquisition of TMBR in which one of its wholly-owned subsidiaries acquired 100% of the remaining outstanding shares of TMBR for a net cash payment of $32.5 million ($40.4 million paid to TMBR shareholders less $7.9 million in cash acquired in the transaction) and the issuance of 2.78 million shares of the Company s common stock valued at $17.82 per share (adjusted to reflect the two-for-one stock split on June 30, 2004). The assets of TMBR included 18 land-based drilling rigs and related equipment, shop facilities, equipment yards and their oil and natural gas properties. The transaction was accounted for as a business combination and the purchase price was allocated among the assets acquired and liabilities assumed based on their estimated fair market values (see Note 3).

During March 2002, the Company issued 1.3 million shares (adjusted to reflect the two-for-one stock split on June 30, 2004) of its common stock as consideration for the acquisition of Odin Drilling, Inc. (see Note 3). The common stock was valued at $13.03 per share, its fair market value on the date the terms of the transaction were agreed upon.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Stock Options and Warrants

Employee and Non-Employee Director Stock Option Plans The Company has seven stock option plans of which three have shares available for grant. The remaining four plans are dormant and the Company does not intend to grant any further options under such plans. At December 31, 2004, the Company s stock option plans were as follows:

Plan Name	Options Authorized for Grant	Options Outstanding	Options Available for Grant
Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan, as amended (1997 Plan)(1)	16,500,000	7,711,776	2,997,992
Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan (2001 Plan)(2)	2,000,000	1,346,322	78,161
Amended and Restated Non-Employee Director Stock Option Plan of Patterson-UTI Energy, Inc. (Non-Employee Director Plan)	1,200,000	370,000	485,000
Patterson-UTI Energy, Inc. Non-Employee Directors Stock Option Plan, as amended (1995 Non-Employee Director Plan)	240,000	24,000	
1997 Stock Option Plan of DSI Industries, Inc. (DSI Plan)		2,144	
Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan (1996 Plan)		176,600	
Patterson-UTI Energy, Inc., 1993 Incentive Stock Plan, as amended (1993 Plan)	5,600,000	351,200	

(1) Plan is for the benefit of employees of the Company, including officers and directors of the Company.

(2) Plan is for the benefit of employees of the Company, other than officers and directors of the Company.

The Company s active plans are the 1997 Plan, the 2001 Plan and the Non-Employee Director Plan. A summary of each of these plans is set forth below.

1997 Plan

Administered by the Compensation Committee of the Board of Directors.

All employees including officers and employee directors are eligible for awards.

Vesting schedule is set by the Compensation Committee, however, typically options vest over 3 or 5 years.

The Compensation Committee sets the term of the option except that no Incentive Stock Option (ISO) can have a term of longer than 10 years. Typically options granted under the plan have a term of 10 years.

The options granted under the plan, unless otherwise stated in the grant thereof, vest upon a change of control as defined in the plan. Options granted to non-executive employees typically do not vest upon a change of control.

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.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The plan allows for awards of tandem and independent stock appreciation rights, restricted stock and performance awards.

2001 Plan

The terms and conditions of the 2001 Plan are identical to the 1997 Plan except as follows:

Officers and directors of the Company are not eligible for grants of options under the 2001 Plan.

No ISO s may be awarded under the 2001 Plan.

Unless the grant states otherwise, options granted under the 2001 Plan do not vest upon a change of control of the Company.

Non-Employee Director Plan

Administered by the Compensation Committee of the Board of Directors.

All options vest upon the first anniversary of the option grant.

Each director receives options to purchase 40,000 shares upon becoming a director of the Company and options to purchase 20,000 shares on December 31st of each subsequent year in which the director serves as a director of the Company.

The exercise price of the options is the fair market value of the Company s common stock on the date of grant.

1995 Non-Employee Director Plan Options granted under the 1995 Non-Employee Director Plan vest on the first anniversary of the option grant. 1995 Non-Employee Director Plan options have five year terms. 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.

DSI Plan The options granted under the DSI plan typically vested at a rate of 33% per year with ten year terms. 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.

1996 Plan The options granted under the 1996 plan vested over one, four and five years as dictated by the Compensation Committee. These options had terms of five and ten years as dictated by the Compensation Committee. 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.

1993 Plan Options granted under the 1993 Plan, typically had terms of 10 years and vested over five years in 20% increments beginning at the end of the first year. These options vest in the event of a change of control as defined in the plan. 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.

Additional Options In July 2001, the Compensation Committee granted to each of two non-employee directors of the Company an option to purchase 24,000 shares of the Company s common stock. These options vested on November 6, 2001 and terminate on November 5, 2005. The exercise price of each of the options was $14.3125, which was in excess of the fair market value of the Company s common stock on the date of grant.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the status of the Company s stock options issued as of December 31, 2004, 2003 and 2002 and the changes during each of the years then ended are presented below (in thousands, except weighted average exercise price):

	2004		2003		2002	
	No. of Shares of Underlying Options	**Weighted Average Exercise Price**	**No. of Shares of Underlying Options**	**Weighted Average Exercise Price**	**No. of Shares of Underlying Options**	**Weighted Average Exercise Price**
Outstanding at beginning of year	12,276	$ 10.31	12,277	$ 8.81	13,192	$ 5.20
Granted	640	19.19	1,830	16.24	4,297	13.39
Exercised	(2,852)	5.55	(1,736)	5.92	(4,914)	3.21
Surrendered/ Expired	(58)	8.76	(95)	9.99	(298)	7.66
Outstanding at end of year	10,006	$ 12.24	12,276	$ 10.31	12,277	$ 8.81
Exercisable at end of year	6,377	$ 11.68	5,972	$ 8.15	4,790	$ 5.44

The following table summarizes information about stock options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contracted Life**	**Weighted Average Exercise Price**	**Number Exercisable**	**Weighted Average Exercise Prices**
$1.5625 to $ 2.50	416,668	4.23	$ 2.31	416,668	$ 2.31
$ 2.51 to $ 5.00	98,000	3.16	$ 4.94	98,000	$ 4.94
$ 5.01 to $ 7.50	156,344	2.70	$ 7.32	156,344	$ 7.32
$ 7.51 to $10.00	2,576,227	6.45	$ 8.02	1,365,617	$ 8.08
$ 10.01 to $12.50	95,000	2.88	$ 11.44	95,000	$ 11.44
$ 12.51 to $15.00	4,103,803	7.50	$ 13.35	3,085,833	$ 13.28
$ 15.01 to $19.45	2,560,000	7.98	$ 16.95	1,159,998	$ 16.19
	10,006,042	7.06	$ 12.24	6,377,460	$ 11.68

Pro Forma Stock-Based Compensation Disclosure Pro forma information in accordance with SFAS 123 regarding net income and earnings per share, as described in Note 1, has been determined as if the Company had accounted for its employee stock options under the fair value method as defined in that statement. The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option valuation model with the following weighted-average assumptions for grants in 1996 through 2004 respectively; dividend yield of 0.06% for all 2004 grants and 0.00% for all other grants; risk-free interest rates are different for each grant and range from 2.18% to 7.02%; the expected term ranges from 3 to 6 years; and a volatility of 38.68% for all 1996 grants, 35.97% for all 1997 grants, 51.08% for all 1998 grants, 61.97% for all 1999 grants, 67.71% for all 2000 grants, 68.33% for all 2001 grants, 63.02% for all 2002 grants, 44.04% for all 2003 grants and 36.84% for all 2004 grants. The effects of applying SFAS 123 in this pro forma disclosure are not indicative of future amounts. SFAS 123 does not apply to awards prior to 1996.

Stock Purchase Warrants In December 2001, the Company issued 650,000 warrants exercisable at $13.375 per share as partial consideration for the purchase of 17 drilling rigs and related equipment from Cleere Drilling Company. The warrants were fully exercisable at the date of issuance. All of the warrants were exercised in December 2004.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In June 2000, the Company issued 254,000 warrants exercisable at $11 per share as partial consideration for the purchase of eight drilling rigs and related equipment from High Valley Drilling, Inc. The warrants were fully exercisable at the date of issuance. All of the warrants were exercised in 2003 and 2002.

Tabular Summary The following table summarizes information regarding the Company s stock options and warrants granted under the provisions of the aforementioned plans as well as stock options and warrants issued pursuant to transactions described above (in thousands, except weighted average exercise prices):

	Shares	Weighted Average Exercise Price
Granted		
2004	640	$ 19.19
2003	1,830	16.24
2002	4,297	13.39
Exercised		
2004	3,502	$ 7.00
2003	1,941	6.46
2002	4,963	3.28
Surrendered		
2004	58	$ 8.76
2003	95	9.99
2002	298	7.66
Outstanding at Year End		
2004	10,006	$ 12.24
2003	12,926	10.47
2002	13,132	9.07
Exercisable at Year End		
2004	6,377	$ 11.68
2003	6,622	8.66
2002	5,645	6.56

14. Leases

The Company incurred rent expense, consisting primarily of daily rental charges for the use of drilling equipment, of $9.1 million, $8.6 million and $5.7 million, for the years 2004, 2003 and 2002, respectively. The Company s obligations under non-cancelable operating lease agreements are not material to the Company s operations.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Income Taxes

Components of the income tax provision applicable for Federal, state and foreign income taxes are as follows (in thousands):

	Restated (See Note 2)		
	2004	2003	2002
Federal income tax expense (benefit):			
Current	$ 32,686	$ 14,073	$ (17,726)
Deferred	12,366	7,794	17,991
	45,052	21,867	265
State income tax expense (benefit):			
Current	2,031	1,233	(1,777)
Deferred	1,555	(487)	822
	3,586	746	(955)
Foreign income tax expense (benefit):			
Current	5,235	18	(2,003)
Deferred	928	2,689	744
	6,163	2,707	(1,259)
Total:			
Current	39,952	15,324	(21,506)
Deferred	14,849	9,996	19,557
Total income tax expense	$ 54,801	$ 25,320	$ (1,949)

The difference between the statutory Federal income tax rate and the effective income tax rate is summarized as follows:

	Restated (See Note 2)		
	2004	2003	2002
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	1.6	1.5	1.7
Permanent differences	0.4	0.8	(4.7)
Other, net	(0.3)	(0.6)	
Effective tax rate	36.7%	36.7%	32.0%

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, 2004 to be realized as a result of the reversal during the carryforward period of existing taxable temporary differences giving rise to deferred tax liabilities and the generation of taxable income in the carryforward period; therefore, no valuation allowance is necessary.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

			Restated (See Note 2)				
	December 31, 2004	**Net Change**	**December 31, 2003**	**Net Change**	**December 31, 2002**	**Net Change**	**January 1, 2002**
Deferred tax assets:							
Current:							
Federal net operating loss carryforwards	$ 1,870	$ 1,870	$	$	$	$	$
Workers compensation allowance	14,877	1,545	13,332	6,159	7,173	2,663	4,510
AMT credit		(602)	602		602		602
Other	6,978	1,238	5,740	(1,775)	7,515	3,880	3,635
	23,725	4,051	19,674	4,384	15,290	6,543	8,747
Non-current:							
Federal net operating loss carryforwards	4,115	4,115					
AMT credit	118	118					
Federal benefit of foreign deferred tax liabilities	6,708	933	5,775	2,019	3,756	744	3,012
Federal benefit of state deferred tax liabilities	3,515	421	3,094	1,275	1,819	452	1,367
Embezzled funds expense	22,178	7,193	14,985	6,713	8,272	3,226	5,046
Other	763	763					
	37,397	13,543	23,854	10,007	13,847	4,422	9,425
Total deferred tax assets	61,122	17,594	43,528	14,391	29,137	10,965	18,172
Deferred tax liabilities:							
Current:							
Other	(7,734)	(4,509)	(3,225)	(3,225)			
Non-current:							

Property and equipment basis difference	(173,344)	(25,534)	(147,810)	(16,683)	(131,127)	(34,581)	(96,546)
Other	(4,528)	167	(4,695)	(4,795)	100	(148)	248
	(177,872)	(25,367)	(152,505)	(21,478)	(131,027)	(34,729)	(96,298)
Total deferred tax liabilities	(185,606)	(29,876)	(155,730)	(24,703)	(131,027)	(34,729)	(96,298)
Net deferred tax liability	$ (124,484)	$ (12,282)	$ (112,202)	$ (10,312)	$ (101,890)	$ (23,764)	$ (78,126)

Management will deduct accumulated net embezzlement losses in the Company s 2005 tax returns, which corresponds with the period in which the embezzlement was detected.

Other deferred tax assets consist primarily of various allowance accounts and tax deferred expenses expected to generate future tax benefit of approximately $7 million. Other deferred tax liabilities consist primarily of receivables from insurance companies not yet recognized for tax purposes.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For tax purposes, the Company has available at December 31, 2004, Federal net operating loss carryforwards of approximately $16 million and $118,000 of alternative minimum tax credit carryforwards. These carryforwards are attributable to the acquisition of TMBR in February 2004.

The net operating loss carryforwards, if unused, are scheduled to expire as follows: 2005 $5 million, 2006 $1 million, 2011 $2 million, 2018 $4 million and 2019 $4 million. The alternative minimum tax credit may be carried forward indefinitely.

16. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company s operating results include expenses of approximately $2.2 million in 2004, $1.5 million in 2003 and $2.1 million in 2002 for the Company s discretionary contributions to the plan.

17. Business Segments

The Company conducts its business through four distinct operating segments: contract drilling of oil and natural gas wells, pressure pumping services and drilling and completion fluids services to operators in the oil and natural gas industry, and the exploration, development, acquisition and production of oil and natural gas. Each of these segments represents a distinct type of business based upon the type and nature of services and products offered. These segments have separate management teams which report to the Company s chief executive officer and have distinct and identifiable revenues and expenses.

Contract Drilling The Company markets its contract drilling services to major and independent oil and natural gas operators. As of December 31, 2004, the Company owned 361 drilling rigs, of which 149 of the drilling rigs were based in the Permian Basin region, 55 in South Texas, 42 in the Ark-La-Tex region and Mississippi, 77 in the Mid-Continent region, 21 in the Rocky Mountain region and 17 in Western Canada. The Company operated 259 of its drilling rigs in 2004.

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.

Drilling and Completion Fluids The Company provides drilling fluids, completion fluids and related services to oil and natural gas operators in Texas, Southeastern New Mexico, Oklahoma, the Gulf Coast region of Louisiana and the Gulf of Mexico. 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. The drilling fluids operations were added by the Company during 1998 with its acquisition of two companies with operations in Texas, Southeastern New Mexico, Oklahoma and Colorado. The Company s services were expanded to include completion fluids in October 2000 with the acquisition of the drilling and completion fluids division of Ambar, Inc., which had operations in the coastal areas of Texas, Louisiana and in the Gulf of Mexico.

Oil and Natural Gas The Company is engaged in the development, exploration, acquisition and production of oil and natural gas.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Restated (See Note 2)		
	Years Ended December 31,		
	2004	2003	2002
Revenues:			
Contract drilling(a)	$ 815,683	$ 640,788	$ 410,752
Pressure pumping	66,654	46,083	32,996
Drilling and completion fluids(b)	90,858	69,286	69,966
Oil and natural gas	33,867	21,163	14,723
Total segment revenues	1,007,062	777,320	528,437
Elimination of intercompany revenues(a)(b)	(6,293)	(1,150)	(480)
Total revenues	$ 1,000,769	$ 776,170	$ 527,957
Income (loss) before income taxes:			
Contract drilling	$ 146,626	$ 72,814	$ 6,029
Pressure pumping	16,747	10,442	6,090
Drilling and completion fluids	4,202	(1,920)	(238)
Oil and natural gas	10,764	7,784	3,945
	178,339	89,120	15,826
Corporate and other	(10,750)	(7,441)	(9,444)
Other operating(c)		2,452	(4,700)
Embezzled funds expense(d)	(19,122)	(17,849)	(8,574)
Interest income	1,140	1,116	1,110
Interest expense	(695)	(292)	(532)
Other	235	1,870	225
Income (loss) before income taxes	$ 149,147	$ 68,976	$ (6,089)

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Restated (See Note 2)		
	Years Ended December 31,		
	2004	2003	2002
Identifiable assets:			
Contract drilling(d)	$ 961,873	$ 766,039	$ 672,199
Pressure pumping	49,145	35,066	25,376
Drilling and completion fluids	62,970	56,215	56,382
Oil and natural gas	62,984	37,111	29,629
	1,136,972	894,431	783,586
Corporate and other(e)	119,813	145,090	135,788
Total assets	$ 1,256,785	$ 1,039,521	$ 919,374
Depreciation, depletion, amortization and impairment:			
Contract drilling(d)	$ 101,779	$ 87,255	$ 82,102
Pressure pumping	5,112	3,774	2,803
Drilling and completion fluids	2,156	2,279	2,176
Oil and natural gas	13,309	7,082	5,251
	122,356	100,390	92,332
Corporate and other	444	444	446
Total depreciation, depletion and amortization	$ 122,800	$ 100,834	$ 92,778
Capital expenditures:			
Contract drilling(d)	$ 140,945	$ 77,350	$ 59,966
Pressure pumping	17,705	10,524	7,399
Drilling and completion fluids	1,488	912	1,571
Oil and natural gas	14,451	10,015	6,357
Total capital expenditures	$ 174,589	$ 98,801	$ 75,293

(a) Includes contract drilling intercompany revenues of approximately $6.0 million, $1.1 million and $457,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

(b) Includes drilling and completion fluids intercompany revenues of approximately $301,000, $56,000 and $23,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

(c)

Other operating relates to decisions of the executive management group regarding corporate strategy, credit risk, loss contingencies and restructuring activities. Due to the non-operating nature of these decisions, the related charges have been separately presented and excluded from the results of specific segments. These charges are primarily related to the contract drilling segment.

(d) The Company s former CFO perpetrated an embezzlement over a period of more than five years. Embezzled funds expense includes adjustments to eliminate payments related to the embezzlement previously capitalized as property and equipment and goodwill acquired. The related depreciation and other amounts expensed have also been reversed from the Company s accounting records (See Note 2).

(e) Corporate assets primarily include cash on hand managed by the parent corporation and certain deferred Federal income tax assets.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. Quarterly Financial Information (unaudited)

Quarterly financial information for the years ended December 31, 2004 and 2003 is as follows (in thousands, except per share amounts):

	Restated (See Note 2)			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2004				
Operating revenues	$ 218,779	$ 234,510	$ 259,174	$ 288,306
Operating income:				
As previously reported	$ 32,510	$ 30,799	$ 47,408	$ 60,497
Adjustment for effects of embezzlement	(5,013)	(3,470)	(4,642)	(5,512)
Other adjustments	(927)	(1,002)	(1,024)	(1,157)
As restated	$ 26,570	$ 26,327	$ 41,742	$ 53,828
Net income:				
As previously reported	$ 20,682	$ 19,607	$ 29,964	$ 38,480
Adjustment for effects of embezzlement	(3,164)	(2,186)	(2,921)	(3,518)
Other adjustments	(585)	(631)	(645)	(737)
As restated	$ 16,933	$ 16,790	$ 26,398	$ 34,225
Net income per common share:				
Basic:				
As previously reported	$ 0.12	$ 0.12	$ 0.18	$ 0.23
Adjustment for effects of embezzlement	$ (0.02)	$ (0.01)	$ (0.02)	$ (0.02)
Other adjustments	$	$	$	$
As restated	$ 0.10	$ 0.10	$ 0.16	$ 0.20
Diluted:				
As previously reported	$ 0.12	$ 0.12	$ 0.18	$ 0.23
Adjustment for effects of embezzlement	$ (0.02)	$ (0.01)	$ (0.02)	$ (0.02)
Other adjustments	$	$	$	$
As restated	$ 0.10	$ 0.10	$ 0.16	$ 0.20
2003				
Operating revenues	$ 165,239	$ 195,624	$ 207,015	$ 208,292
Operating income:				
As previously reported	$ 9,844	$ 19,153	$ 27,354	$ 30,839
Adjustment for effects of embezzlement	(1,887)	(7,313)	(5,388)	(2,787)
Other adjustments	(883)	(883)	(883)	(884)
As restated	$ 7,074	$ 10,957	$ 21,083	$ 27,168

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Restated (See Note 2)			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Income before cumulative effect of change in accounting principle:				
As previously reported	$ 7,051	$ 12,202	$ 17,186	$ 20,449
Adjustment for effects of embezzlement	(1,194)	(4,628)	(3,410)	(1,764)
Other adjustments	(559)	(559)	(559)	(559)
As restated	$ 5,298	$ 7,015	$ 13,217	$ 18,126
Cumulative effect of change in accounting principle, net of related income tax benefit of approximately $287	(469)			
Net income:				
As previously reported	$ 6,582	$ 12,202	$ 17,186	$ 20,449
Adjustment for effects of embezzlement	(1,194)	(4,628)	(3,410)	(1,764)
Other adjustments	(559)	(559)	(559)	(559)
As restated	$ 4,829	$ 7,015	$ 13,217	$ 18,126
Net income per common share:				
Basic:				
Income before cumulative effect of change in accounting principle:				
As previously reported	$ 0.04	$ 0.08	$ 0.11	$ 0.13
Adjustment for effects of embezzlement	$ (0.01)	$ (0.03)	$ (0.02)	$ (0.01)
Other adjustments	$	$	$	$
As restated	$ 0.03	$ 0.04	$ 0.08	$ 0.11
Net income:				
As previously reported	$ 0.04	$ 0.08	$ 0.11	$ 0.13
Adjustment for effects of embezzlement	$ (0.01)	$ (0.03)	$ (0.02)	$ (0.01)
Other adjustments	$	$	$	$
As restated	$ 0.03	$ 0.04	$ 0.08	$ 0.11
Diluted:				
Income before cumulative effect of change in accounting principle:				
As previously reported	$ 0.04	$ 0.07	$ 0.10	$ 0.12
Adjustment for effects of embezzlement	$ (0.01)	$ (0.03)	$ (0.02)	$ (0.01)
Other adjustments	$	$	$	$
As restated	$ 0.03	$ 0.04	$ 0.08	$ 0.11
Net income:				
As previously reported	$ 0.04	$ 0.07	$ 0.10	$ 0.12
Adjustment for effects of embezzlement	$ (0.01)	$ (0.03)	$ (0.02)	$ (0.01)

Other adjustments	$		$		$		$	
As restated	$	0.03	$	0.04	$	0.08	$	0.11

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

19. 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 that it places its demand deposits and temporary cash investments with high credit quality financial institutions. At December 31, 2004 and 2003, the Company s demand deposits and temporary cash investments consisted of the following (in thousands):

	2004	2003
Deposits in FDIC and SIPC-insured institutions under $100,000	$ 2,023	$ (3,326)
Deposits in FDIC and SIPC-insured institutions over $100,000	131,427	112,226
	133,450	108,900
Less outstanding checks and other reconciling items	(21,079)	(8,417)
Cash and cash equivalents	$ 112,371	$ 100,483

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 drilling services. As is general industry practice, the Company generally does not require customers to provide collateral. No significant losses from individual contracts were experienced during the years ended December 31, 2004, 2003, or 2002. The Company recognized bad debt expense for 2004, 2003 and 2002 of $897,000, $259,000 and $320,000, respectively.

The carrying values of cash and cash equivalents, marketable securities and trade receivables approximate fair value due to the short-term maturity of these assets.

20. Related Party Transactions

Joint Operation of Oil and Natural Gas Properties The Company operates certain oil and natural gas properties in which certain of its affiliated persons have participated, either individually or through entities they control, in the prospects or properties in which the Company has an interest. These participations, which have been on a working interest basis, have been in prospects or properties originated or acquired by Patterson-UTI. At December 31, 2004, affiliated persons were working interest owners in 237 of 300 total wells operated by Patterson-UTI. Sales were made by Patterson-UTI at its cost, comprised of Patterson-UTI s costs of acquiring and preparing the working interests for sale. 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. The affiliated persons earned oil and natural gas production revenue (net of royalty) of $13.8 million, $11.1 million and $6.9 million from these properties in 2004, 2003 and 2002, respectively. These persons or entities in turn paid for joint operating costs (including drilling and other development expenses) of $7.5 million, $7.9 million and $5.5 million incurred in 2004, 2003 and 2002, respectively. These activities resulted in a payable to the affiliated persons of approximately $1.2 million and $871,000 and a receivable from the affiliated persons of approximately $856,000 and $888,000 at December 31, 2004 and 2003, respectively.

Other In 2004, 2003 and 2002, the Company paid approximately $914,000, $740,000 and $279,000, respectively, to TMP Truck and Trailer LP (TMP), an entity owned by Thomas M. Patterson (son of A. Glenn Patterson), for certain equipment and metal fabrication services. Purchases from TMP were at current market prices.

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2004 and 2003, the Company paid approximately $39,000 and $209,000, respectively, to Melco Services (Melco) for dirt contracting services and $44,000 and $59,000, respectively, to L&N Transportation (L&N) for water hauling services. Both entities are owned by Lance D. Nelson, brother of Jonathan D. Nelson, Patterson-UTI s Chief Financial Officer. Purchases from Melco and L&N were at current market prices.

See Note 2 for information pertaining to fraudulent payments made to or for the benefit of Jonathan D. Nelson, the Company s former CFO.

21. Supplementary Oil and Natural Gas Reserve Information and Related Data (Unaudited)

Oil and Natural Gas Expenditures and Capitalized Costs:

Gross oil and natural gas expenditures for the years ended December 31, 2004, 2003 and 2002 are summarized below (in thousands):

	2004	2003	2002
Property acquisition costs	$ 2,491	$ 1,120	$ 905
Exploration costs	10,242	7,572	6,267
Development costs	1,855	1,531	845
	$ 14,588	$ 10,223	$ 8,017

The aggregate amount of capitalized costs of oil and natural gas properties as of December 31, 2004, 2003 and 2002 is comprised of the following (in thousands):

	2004	2003	2002
Proved properties	$ 71,731	$ 50,481	$ 44,849
Unproved properties	10,980	7,144	7,162
Accumulated depreciation and depletion	(45,506)	(38,947)	(35,684)
	$ 37,205	$ 18,678	$ 16,327

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Results of operations for oil and natural gas producing activities:

Results of operations for oil and natural gas producing activities as of December 31, 2004, 2003 and 2002 are summarized below (in thousands):

	2004	2003	2002
Oil and natural gas sales	$ 31,142	$ 19,058	$ 12,738
Gain on sale of oil and natural gas properties	123	571	303
	31,265	19,629	13,041
Costs and expenses:			
Lease operating and production costs	6,076	3,735	3,171
Exploration costs including dry holes and abandonments	1,902	1,073	785
Depreciation and depletion	10,112	5,638	4,524
Impairment of oil and natural gas properties	3,197	1,444	727
Income tax expense	3,662	2,840	1,687
	24,949	14,730	10,894
Results of operations for oil and natural gas producing activities	$ 6,316	$ 4,899	$ 2,147

Oil and natural gas reserve quantities:

The following table sets forth information (in thousands) with respect to quantities of net proved oil and natural gas reserves and changes in those reserves for the years ended December 31, 2004, 2003 and 2002. The quantities were estimated by an independent petroleum engineer. The Company s proved oil and natural gas reserves are located entirely within the United States.

	Oil (Bbls)	Gas (Mcf)
Estimated quantity, January 1, 2002	1,047	4,634
Revision in previous estimates	145	2,103
Extensions, discoveries and other additions	331	1,420
Sales of reserves	(12)	(110)
Production	(284)	(1,807)
Estimated quantity, January 1, 2003	1,227	6,240
Revision in previous estimates	87	(1,123)
Extensions, discoveries and other additions	149	2,446
Sales of reserves	(27)	(244)
Production	(289)	(2,052)
Estimated quantity, January 1, 2004	1,147	5,267
Revision in previous estimates	(122)	(1,807)
Extensions, discoveries and other additions	392	2,675

Purchases	695	4,920
Sales of reserves	(6)	(90)
Production	(392)	(2,719)
Estimated quantity, January 1, 2005	1,714	8,246

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Estimates of the Company s proved reserves and future net revenues are determined based on various assumptions such as oil and natural gas prices, operating costs, reservoir performance and economic conditions. The oil and natural gas prices and operating cost assumptions were based on the actual prices and costs in effect as of the date of such estimates. These assumptions are held constant throughout the life of the properties, except operating costs are adjusted for contractual escalations. The Company s independent petroleum engineer estimates the assumptions relating to reservoir performance and economic conditions using information available and industry experience. The oil and natural gas prices used to value the Company s reserves as of December 31, 2004 were $43.45 per Bbl of oil and $6.15 per Mcf of natural gas. Estimates of reserves and production performance are subjective and may change materially as actual production information becomes available.

Standardized measure of future net cash flows of proved developed oil and natural gas reserves, discounted at 10% per annum (in thousands):

	Years Ended December 31,		
	2004	**2003**	**2002**
Future gross revenues	$ 123,201	$ 70,894	$ 68,165
Future development and production costs	(37,820)	(23,021)	(22,149)
Future income tax expense	(30,995)	(15,155)	(15,964)
Future net cash flows	54,386	32,718	30,052
Discount at 10% per annum	(16,844)	(8,768)	(8,952)
Standardized measure of discounted future net cash flows	$ 37,542	$ 23,950	$ 21,100

Changes in the standardized measure of net cash flows of proved developed oil and natural gas reserves discounted at 10% per annum (in thousands):

	Years Ended December 31,		
	2004	**2003**	**2002**
Standardized measure at beginning of year	$ 23,950	$ 21,100	$ 10,714
Sales and transfers of oil and natural gas produced, net of production costs	(15,257)	(11,362)	(8,342)
Net changes in sales price and future production and development costs	6,619	4,718	4,888
Extensions, discoveries and improved recovery, less related costs	8,259	10,052	6,017
Sales of minerals-in-place	(676)	(2,017)	(30)
Purchase of reserves	19,561		
Revision of previous quantity estimates	4,288	(2,976)	4,315
Accretion of discount	3,759	3,547	1,531
Other	(3,953)	101	(9,358)
Net change in income taxes	(9,008)	787	11,365

Standardized measure at end of year	$ 37,542	$ 23,950	$ 21,100

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