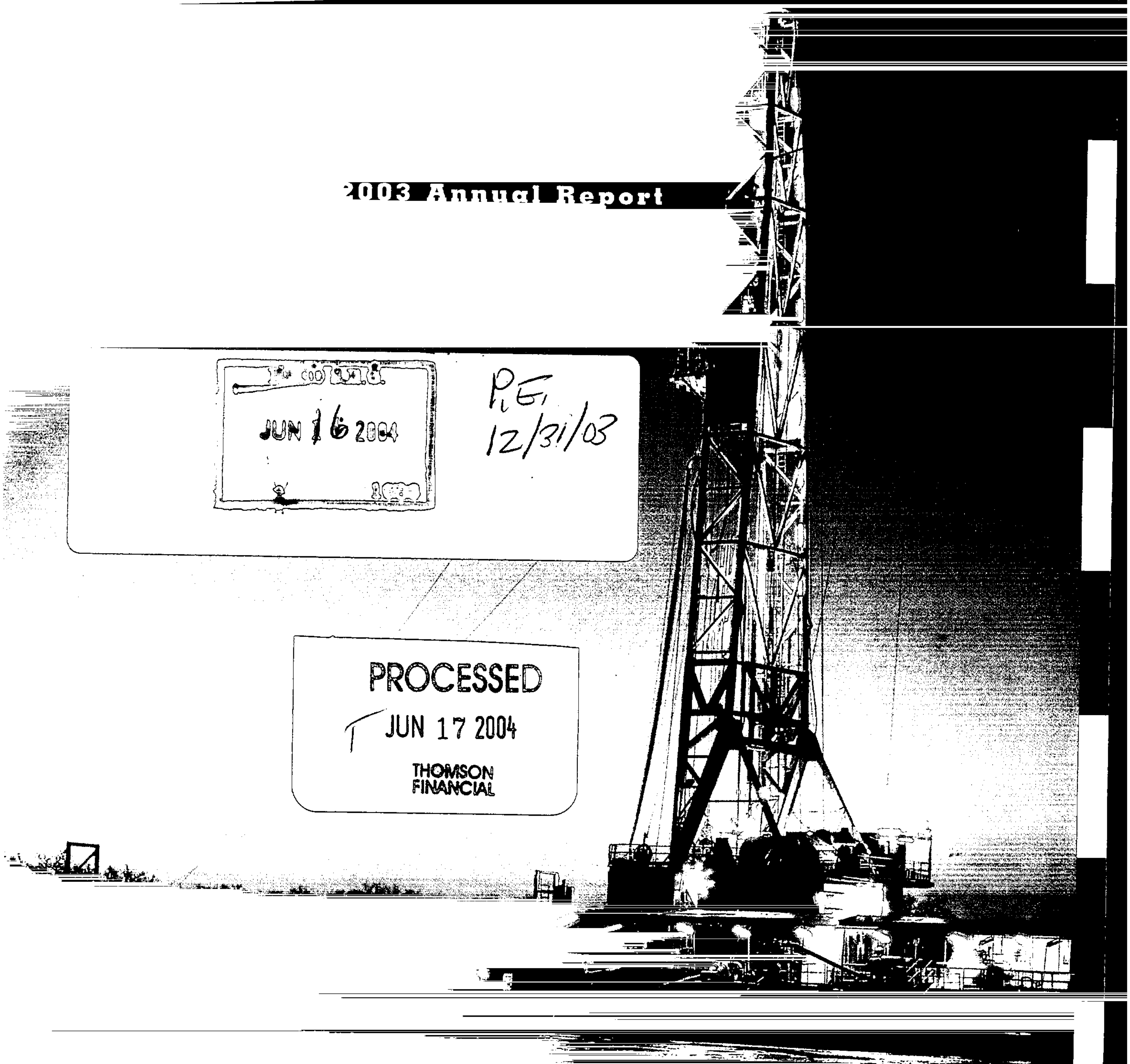
PATTERSON-UTI ENERGY, INC.

2003 Annual Report



P.E.
12/31/03

Financial Highlights (in thousands, except per share amounts – unaudited)

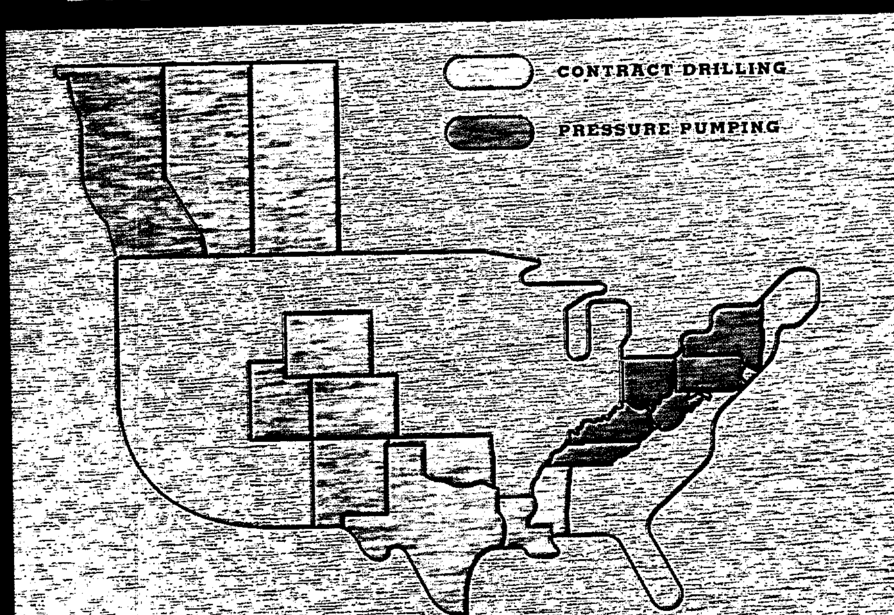
	Year ended December 31,				
	1999	2000	2001	2002	2003
Revenues	$307,366	$582,322	$989,975	$527,957	$776,170
Operating income (loss)	(9,450)	68,585	267,172	3,398	87,190
Net income (loss)	(11,737)	37,226	164,162	2,169	55,326
Earnings (loss) per share					
Basic	(0.18)	0.52	2.15	0.03	0.68
Diluted	(0.18)	0.50	2.07	0.03	0.67
Total assets	496,715	739,898	869,642	942,509	1,075,830
Long-term debt	82,196	79,416	0	0	0
Shareholders' equity	309,695	481,299	687,142	737,556	820,071
Working capital	45,161	127,299	110,172	167,863	199,613

Operational Highlights (dollars in thousands – unaudited)

	1999	2000	2001	2002	2003
Operating days	36,385	63,303	76,871	45,919	68,798
Average revenue per day	$7.32	$8.10	$10.93	$8.94	$9.30
Average margin per day (1)	$1.15	$2.02	$4.59	$2.01	$2.39
Average rigs operating	100	173	211	126	188
Rig utilization percentage	43%	66%	70%	39%	56%

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

2003 PATTERSON-UTI ENERGY, INC.



The Company also has a drilling and completion fluids business that operates in Texas, New Mexico, Oklahoma, Louisiana and in the Gulf of Mexico. Additionally, the Company has an exploration and production business that is based in Texas.

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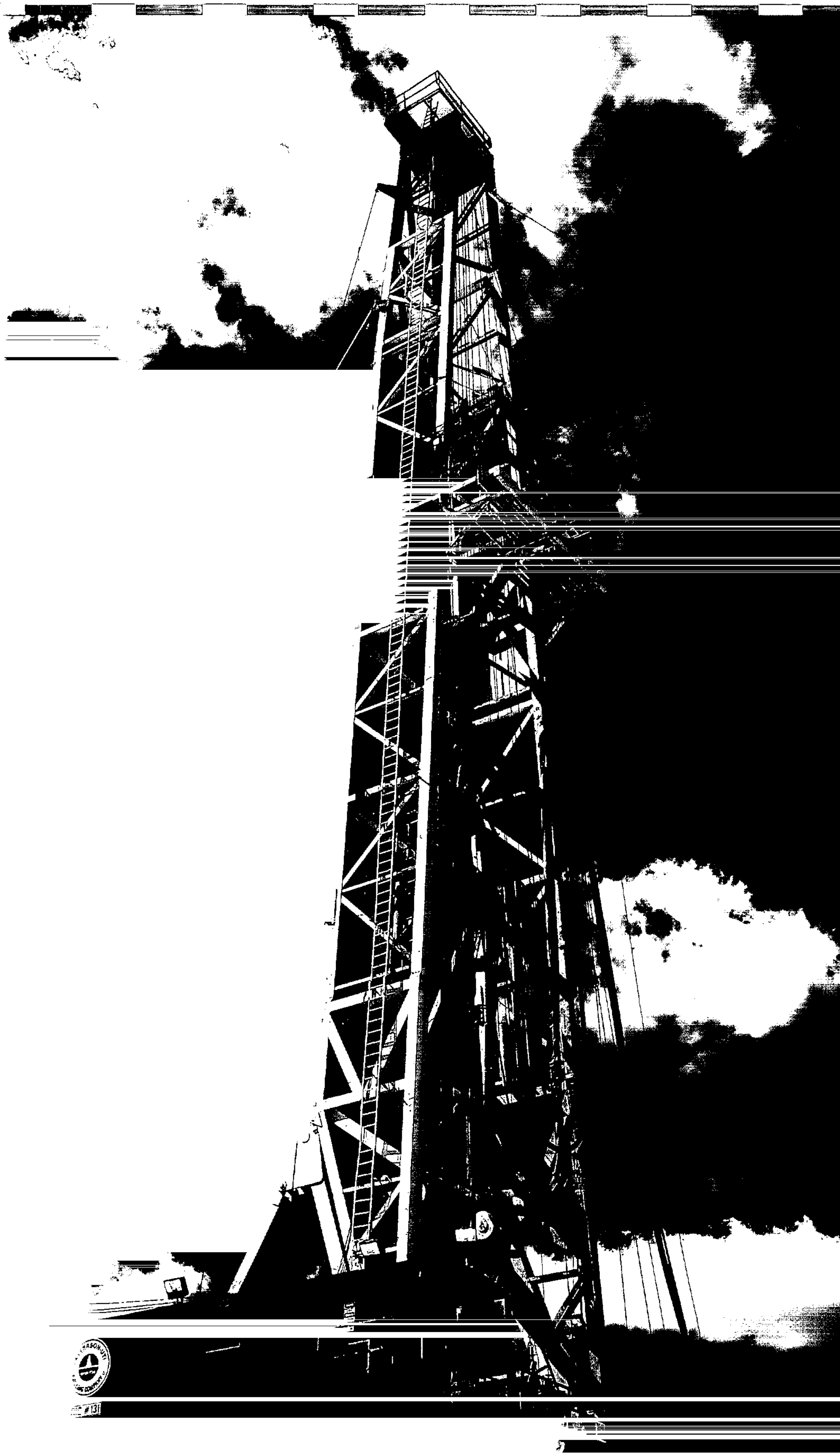
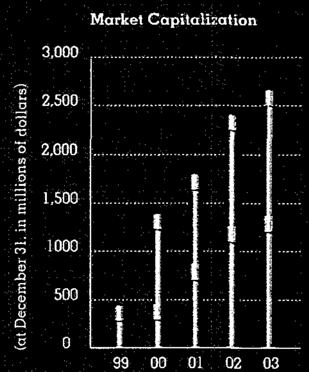
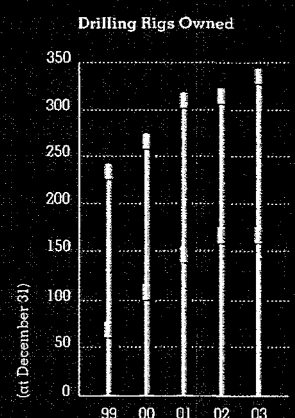
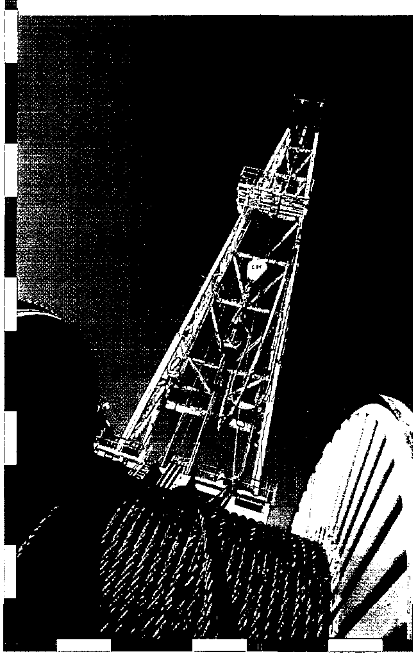


Company Profile

Patterson-UTI Energy, Inc. provides onshore contract drilling services to exploration and production companies in North America. The Company's land-based drilling rigs operate in oil and natural gas producing regions of Texas, New Mexico, Oklahoma, Louisiana, Mississippi, Colorado, Utah, Wyoming and western Canada. Patterson-UTI Energy, Inc. is also engaged in the businesses of pressure pumping services and drilling and completion fluid services. Additionally, the Company has an exploration and production business that is based in Texas.







Fellow Shareholders:

We are pleased to report that 2003 was another successful year for Patterson-UTI Energy. It was a year in which our results continued to demonstrate the earnings leverage that we are able to achieve as revenues increase and daily drilling margins improve. Our highlights for the year include:

- **Continued Earnings Leverage:** While revenues for 2003 were up by 47 percent to $776.2 million from $528.0 million in 2002, net income for the year increased more than twenty-five fold to $55.3 million, or $0.67 per share, compared to net income of $2.2 million, or $0.03 per share in 2002.
- **Additional Drilling Rigs:** During the year we acquired 19 drilling rigs, bringing our total at yearend to 343 rigs.
- **Strong Balance Sheet:** We ended the year with $100 million in cash and cash equivalents, $200 million in working capital and no long-term debt, providing us with the continued financial strength and flexibility to react efficiently and decisively to unique acquisition opportunities.

2003 – INCREASED DRILLING ACTIVITY AND DRILLING MARGINS We achieved a significant increase in drilling activity during 2003. Our average rigs operating increased to 188 from 126 in 2002 and our average utilization rate improved to 56 percent from 39 percent. With the improvement in utilization, our average margin per operating day increased significantly to $2,840 in the fourth quarter of 2003 from $1,830 in the fourth quarter of 2002. We believe that this improvement in average margin per operating day reflects the tightening supply of available land drilling rigs, and the actions that we have taken to maintain our highly-experienced field workforce and well-maintained rig fleet.

NATURAL GAS – INCREASED DRILLING NEEDED IN 2004 TO MEET DEMAND The prospect of natural gas prices remaining in excess of $4.50 per Mcf for 2004, resulting from declining natural gas production caused by depletion rates, strongly suggests that there will be an increase in the demand for drilling services during the 2004 natural gas withdrawal and storage refill seasons.

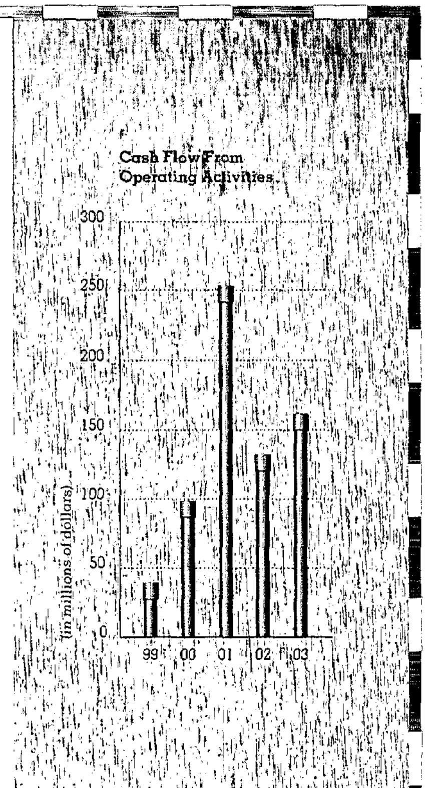
According to the U.S. Department of Energy, the annual demand for natural gas is expected to remain above 22 trillion cubic feet. At the same time, the supply of natural gas is expected to remain tight due to decreasing production caused by accelerating depletion rates. According to industry sources, first year decline rates for U.S. natural gas wells increased to 28 percent in 2003 compared to 18 percent in 1993.

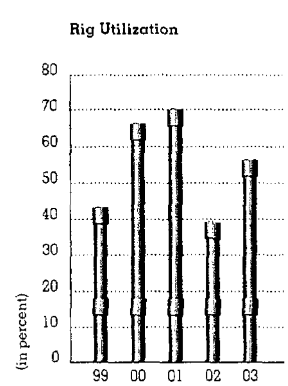
The combination of strong demand and decreasing supply are expected to result in high natural gas prices in 2004. In this pricing environment, owners of mineral rights should have a significant incentive to engage in drilling activities.

The supply and demand issues we discussed above suggest a new paradigm for the U.S. natural gas industry. At the increased level of drilling activity in 2003, natural gas production appeared to continue to decline, albeit at a slower rate of change. Thus, it appears that the current level of rig activity will, at most, sustain production, but not correct the imbalance causing historically high natural gas prices. In essence, we believe a new baseline level of activity is now needed to sustain production, and expect that an increase in activity will be needed to overcome the now chronic shortfall in U.S. natural gas production.

Since 60 percent of the domestic supply of natural gas comes from U.S. land-based drilling, Patterson-UTI Energy is uniquely well-positioned to participate in this increase in demand. With a large fleet of drilling rigs that are strategically located throughout the major natural gas producing regions of the U.S., we fully expect to benefit from the anticipated increase in land-based drilling activity.

LOOKING AHEAD We intend to continue to take those actions that will enhance our ability to control our costs and increase our rig utilization, so that we can continue to benefit from our earnings leverage as revenues and

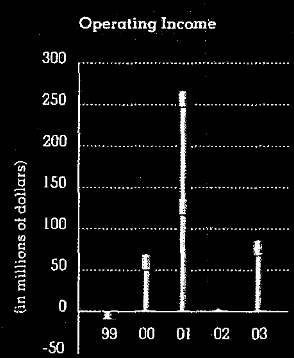




daily drilling margins increase. To that end we intend to continue to make strategic acquisitions when we see what we believe to be worthwhile opportunities in the market place. In February 2004, we completed the acquisition of the remaining outstanding shares of TMBR/Sharp Drilling, Inc. With the addition of TMBR/Sharp's 18 drilling rigs, our fleet now stands at 361 drilling rigs, including 94 with depth capacities rated from 15,000 to 30,000 feet.

Finally, we would like to express our appreciation to all of our employees – from those who work with our equipment in the field to those who serve in administrative and support roles – for their contribution and commitment over the past year. We are very fortunate to have such talented and dedicated employees who are focused on serving the needs of our customers.

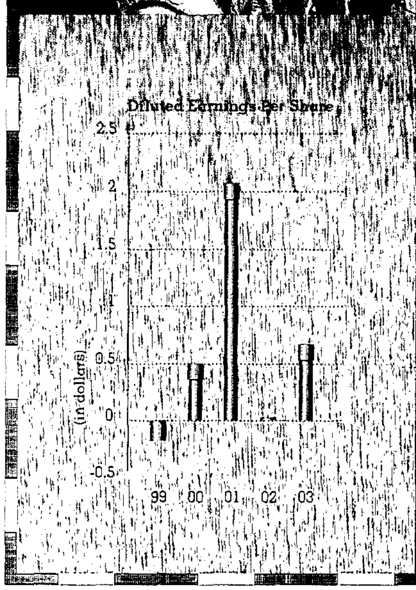
As always, we pledge to do all that we can to merit the continued trust and confidence of our fellow shareholders.

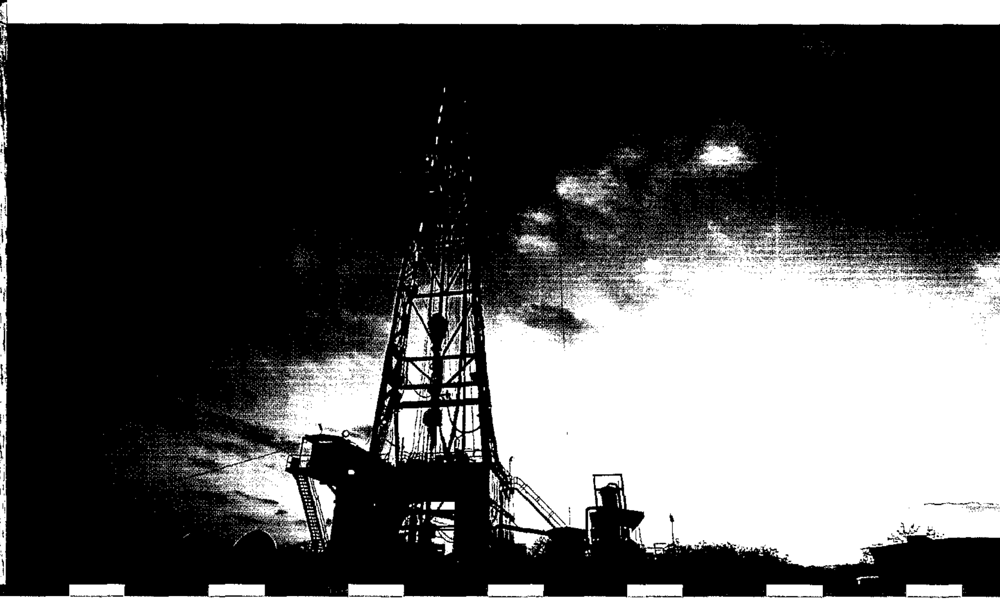


Respectfully submitted,

Mark S. Siegel
Chairman

Cloyce A. Talbott
Chief Executive Officer





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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2003

or

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

For the transition period from to

Commission File Number 0-22664

Patterson-UTI Energy, Inc.

(Exact name of registrant as specified in its charter)

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2003, the last business day of the registrant's most recently completed second fiscal quarter was $2,441,241,719, calculated by reference to the closing price of $32.37 for the common stock on the Nasdaq National Market on that date.

As of February 2, 2004, the registrant had outstanding 81,055,467 shares of common stock, $.01 par value, its only class of voting stock.

Documents incorporated by reference:

Definitive Proxy Statement for the 2004 Annual Meeting of Stockholders (Part III)

This Report on Form 10-K (including documents incorporated by reference herein) 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 15.

This Report on Form 10-K, 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.

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, 2003, we had a drilling fleet of 343 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 West Texas, Southeast New Mexico, South Texas, East Texas, Oklahoma, the Gulf Coast regions of Texas and 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, Southeast New Mexico, South Texas 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 profits/(losses) 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 2003, 2002 and 2001,
- the pressure pumping segment had operating profits in 2003, 2002 and 2001,
- the drilling and completion fluids segment had operating losses in 2003 and 2002 and an operating profit in 2001, and
- the oil and natural gas segment had operating profits in 2003, 2002 and 2001.

See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 16 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, 2003, we owned 343 drilling rigs which are based in the following regions:

- 143 in West Texas and New Mexico,
- 56 in South Texas,
- 42 in the Ark-La-Tex region and Mississippi,
- 70 in the Mid-Continent region (Oklahoma and North Central Texas),
- 16 in the Rocky Mountain region (Colorado, Utah and Wyoming), and
- 16 in Western Canada (Alberta, British Columbia and Saskatchewan).

Of our drilling rigs, 39 are SCR electric rigs and 304 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. Our drilling rigs have rated maximum depth capabilities ranging from 4,000 feet to 30,000 feet.

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, many of the components on a drilling rig are replaced or rebuilt. We spend significant funds each year on an ongoing program of modifying and upgrading our drilling rigs to ensure that our drilling equipment is well maintained and competitive. During fiscal years 2003, 2002, and 2001, we spent approximately $95 million, $69 million, and $151 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. Our drilling rigs are utilized for both developmental and exploratory drilling and can be used for either 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 and are obtained on a competitive bid or negotiated basis. Typically, the contracts are entered into for short-term periods and cover the drilling of 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 subject to termination by the customer on short notice. We generally indemnify our customers against claims by our employees and claims arising from surface pollution caused by spills of fuel, lubricants, and other solvents within our control. The customers generally indemnify us against claims arising from other surface and subsurface pollution, except claims arising 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 bids for each contract depend upon:

• the location, depth, and anticipated complexity of the well,

• the on-site drilling conditions,

• the equipment to be used,

• our estimate of the risks involved,

• the estimated duration of the work to be performed,

• the 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 margins over those that would be attainable under a daywork contract. Margins 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 margins 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, margins 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.

The following table sets forth the approximate percentage of our drilling revenues attributable to daywork, footage, and turnkey contracts for each of the last three years:

	Years Ended December 31,		
Type of Revenues	**2003**	**2002**	**2001**
Daywork	83%	82%	93%
Footage	7	11	3
Turnkey	10	7	4

Contract Drilling Activity — The following table sets forth certain information regarding our contract drilling activity for each of the last three years:

	Years Ended December 31,		
	2003	**2002**	**2001**
Average rigs owned	336	323	302
Average rigs operating(1)	188	126	211
Average rig utilization rate	56%	39%	70%
Number of rigs operated	226	230	287
Number of wells drilled	3,017	2,012	2,869

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

Drilling Rigs and Related Equipment — The following table provides certain information about our drilling rigs as of December 31, 2003:

Depth Rating (ft.)	Mechanical	Electric
4,000 to 9,999	60	—
10,000 to 11,999	68	2
12,000 to 14,999	119	6
15,000 to 30,000	57	31
Totals	304	39

At December 31, 2003, we owned 261 trucks and 316 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, 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 consist primarily of 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 which is accomplished by pumping fluids under pressure into the well bore. Generally, Appalachian Basin wells require cementing services before production commences. Cementing is the process of inserting material between the wall of the well bore and the casing to center and stabilize the casing.

Equipment — As of December 31, 2003, we operated the following pressure pumping equipment:

- 21 cement pumper trucks,
- 24 fracturing pumper trucks,
- 20 nitrogen pumper trucks,
- 11 blender trucks,
- 11 bulk acid trucks,
- 25 bulk cement trucks,
- 6 bulk nitrogen trucks,
- 31 bulk sand trucks, and
- 11 connection trucks.

Drilling and Completion Fluids Operations

General — We provide drilling fluids, completion fluids, and related services to oil and natural gas operators in West Texas, Southeast New Mexico, South Texas, East Texas, Oklahoma, the Gulf Coast regions of Texas and Louisiana, and the Gulf of Mexico. We serve our offshore customers through seven stockpoints located along the Gulf of Mexico in Texas and Louisiana and our land-based customers through seven stockpoints 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 it undergoes the completion process wherein 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 by operators to control bottom-hole pressures and to meet a well's specific corrosion, inhibition, viscosity, and fluid loss requirements during the completion and workover phases.

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 equipped with two barite grinding mills located in Houma, Louisiana. This facility allows us to grind raw barite into the powder additive used in drilling fluids. We believe the ability to process our own barite is critical to being competitive on the Gulf Coast and in the Gulf of Mexico.

Other Equipment — We own 20 trucks and 75 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, Southeast New Mexico, South Texas, and Mississippi. Our strategy for our oil and natural gas operations is to increase our reserve base primarily through developmental drilling, as well as selected acquisitions of leasehold acreage and producing properties.

Oil and Natural Gas Reserves — The following table sets forth estimates, derived from reserve reports provided by M. Brian Wallace, an independent petroleum engineer, of our proved developed reserves and estimated future net revenues from our proved developed reserves as of December 31, 2003, 2002, and 2001. 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 developed reserves, see also Note 20 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 economical productibility is supported by either actual production or conclusive formation tests. Proved developed oil and natural gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods.

	As of December 31,		
	2003	2002	2001
	(In thousands)		
Proved Developed Reserves:			
Oil (Bbls)	1,147	1,227	1,047
Gas (Mcf)	5,267	6,240	4,634
Total (BOE)	2,025	2,267	1,819
Estimated future net revenues before income taxes	$47,873	$46,016	$19,597
Present value of estimated future net revenues before income taxes, discounted at 10%	$34,371	$32,308	$14,492
Standardized measure of discounted future net cash flows(1)	$23,950	$21,100	$10,714

(1) For the calculation of standardized measure of discounted future net cash flows, see Note 20 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, 2003, we held a working interest in 315 productive wells, of which 150 were considered oil and 165 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 172 of these wells at December 31, 2003. The following table sets forth our 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 and include costs of labor, well service and repair, utilities, field supervision, property taxes, production, and severance taxes and related charges.

	Years ended December 31,		
	2003	2002	2001
Average net daily production:			
Oil (Bbls)	788	794	739
Gas (Mcf)	5,656	5,109	4,654
Total (BOE)	1,731	1,646	1,515
Average sales prices:			
Oil (per Bbl)	$30.54	$25.02	$24.88
Gas (per Mcf)	4.97	2.91	4.12
Average production costs (per BOE)	$ 5.51	$ 5.11	$ 5.32

Productive Wells — The following table sets forth information regarding the number of productive wells in which we held a working interest as of December 31, 2003. One or more completions in the same well bore are reflected as one well.

	Productive Wells	
	Gross	Net
Oil	150	29.49
Gas	165	22.22
Total	315	51.71

Developed and Undeveloped Acreage — The following table sets forth the developed and undeveloped acreage in which we owned a working interest at December 31, 2003:

	Developed Acreage		Undeveloped Acreage	
Location	Gross	Net	Gross	Net
Texas	61,055	10,758	45,438	9,406
Kansas	320	45	—	—
Louisiana	640	32	—	—
New York	160	131	—	—
New Mexico	7,919	1,027	1,881	301
Mississippi	2,400	469	8,000	1,760
Pennsylvania	880	129	—	—
Total	73,374	12,591	55,319	11,467

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, developed or undeveloped, 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 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. The following table sets forth the gross and net acreage subject to leases summarized in the table of undeveloped acreage that will expire:

	Lease Acres Expiring	
	Gross	Net
Years ending:		
December 31, 2004	5,019	1,339
December 31, 2005	2,419	587
December 31, 2006 and later	47,881	9,541
Total	55,319	11,467

Drilling Activities — The following table sets forth the results of our participation in the drilling of developmental and exploratory wells during 2003, 2002 and 2001:

	Developmental Wells				Exploratory Wells			
	Productive		Dry Holes		Productive		Dry Holes	
Years ended December 31,	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2003	27	4.58	11	2.52	12	1.99	4	0.88
2002	24	4.17	11	2.67	6	0.56	1	0.25
2001	20	3.82	5	1.06	5	0.87	2	0.56
Total	71	12.57	27	6.25	23	3.42	7	1.69

In addition, we were participating in six wells, 1.33 net, that were being drilled at December 31, 2003.

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 2003, 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 intensely competitive due to the fact that the supply of available land drilling rigs and pressure pumping equipment exceeds the demand for those rigs and 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.

Drilling and Completion Fluids Business — The drilling and completion fluids services industry is highly competitive. Price is generally the most important competitive factor in the industry. Other competitive factors include the availability of chemicals and experienced personnel, the reputation of the fluids services provider in the drilling industry, and our relationship with customers. Some of our competitors have substantially greater resources and longer operating histories than we have. We believe that competition for drilling and completion fluids service contracts will continue to be intense.

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 the hiring of 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 financial resources, staffs, and facilities 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, we have not been required to expend significant resources in order to satisfy applicable environmental laws and regulations. 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 for 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 have utilized operating and disposal practices that were or are currently 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 either as to such entities' treatment of hydrocarbon and other materials or the manner in which such materials may have been disposed of or released.

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, as amended, and comparable state statutes govern the disposal of "hazardous wastes." Although CERCLA currently excludes petroleum from the definition of "hazardous substances," and the Resource Conservation and Recovery Act also excludes certain classes of exploration and production wastes from regulation, such exemptions by Congress under both CERCLA and the Resource Conservation and Recovery Act may be deleted, limited, or modified in the future. If such changes are made to CERCLA and/or the Resource Conservation and Recovery Act, 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 Patterson-UTI, 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 Patterson-UTI. 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 5,800 full-time persons (300 office personnel and 5,500 field personnel) at December 31, 2003. 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

Patterson-UTI uses many suppliers of raw materials and services. These materials and services have been and continue to be available. We also utilize numerous independent subcontractors from various trades.

Incorporation by Reference

The various factors disclosed under the caption "Forward Looking Statements and Cautionary Statement for Purposes of the 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995," beginning on page 15 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 Item 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, yard, 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:

- an office building 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 used to power our drilling rigs, and
- an open-ended metal storage facility with approximately 10,200 square feet.

We have regional administrative offices, yard, and stockpoint facilities in many of the areas in which we operate. The facilities are primarily used to support the 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, 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
- Eastern Canada.

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, and lease the majority of our other facilities. We do not believe that any of these other facilities are individually material to our operations. We believe that our existing facilities are suitable and adequate to meet our needs.

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

Westfort Energy LTD and Westfort Energy (US) LTD f/k/a Canadian Delta, Inc. ("Westfort"), filed a lawsuit against two Patterson-UTI subsidiaries, Patterson Petroleum LP, and Patterson-UTI Drilling Company LP, in the Circuit Court, Rankin County, Mississippi, Case No. 2002-18. The lawsuit relates to a letter agreement entered into in July 2000 between Patterson Petroleum LP and Westfort concerning the drilling of a daywork well in Mississippi. This lawsuit was filed by Westfort after Patterson Petroleum LP made demand on Westfort for payment of the contract drilling services.

The Westfort lawsuit has been dismissed without prejudice. Westfort filed for bankruptcy in May of 2003. We continue to assert claims against Westfort including the monies owed Patterson Petroleum LP under the letter agreement in the amount of approximately $5,075,000. Amounts deemed uncollectible have been reserved. We believe that it is remote that the outcome of this matter will have a material adverse effect on Patterson-UTI's financial condition and results of operations.

In this lawsuit, Westfort alleged breach of contract, fraud, and negligence causes of action. Westfort sought alleged monetary damages, the return of shares of Westfort stock, unspecified damages from alleged lost profits, lost use of income stream, and additional operating expenses, along with alleged punitive damages to be determined by the jury, but not less than 25% of Patterson-UTI's net worth. We intend to vigorously contest these claims if reasserted by Westfort.

We are also 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

Patterson-UTI from time to time makes written or oral forward-looking statements, including statements contained in this Annual Report on Form 10-K, 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, Patterson-UTI, or our management, expresses 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, Patterson-UTI:

Patterson-UTI is 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. In recent 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 to $5.45 in 2003 compared to $3.36 in 2002, resulting in an increase in demand for our drilling services. Our average number of rigs operating increased to 188 in 2003 from 126 in 2002. 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 contract drilling business experienced increased demand for drilling services in 1997, 2000 and 2001. However, except for those periods and other occasional upturns, generally, there have been substantially more drilling rigs available than necessary to meet demand in most operational and geographic segments of the

North American land drilling industry. As a result, drilling contractors have had difficulty sustaining profit margins.

In addition to adverse effects that future declines in demand could have on Patterson-UTI, 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, or
- 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.

Shortages of Drill Pipe, Replacement Parts, and Other Related Rig Equipment Adversely Affects Patterson-UTI's 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 substantially increase capital 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 intensely competitive due to the fact that the supply of available land drilling rigs and pressure pumping equipment exceeds the demand for those rigs and 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.

Patterson-UTI believes 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 competitive factor in the industry. Other competitive factors include the availability of chemicals and experienced personnel, the reputation of the fluids services provider in the drilling industry, and our relationship with existing customers. Some of our competitors have substantially greater resources and longer operating histories than we have. We believe that competition for our drilling and completion fluids service contracts will continue to be intense.

Labor Shortages Adversely Affect Our Operating Results.

During periods of increased 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 in turn has a negative impact on 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. During the last upturn in our industry, we experienced an approximate 30% to 40% increase in wage rates to our drilling personnel.

Continued Growth of Patterson-UTI 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 would:

- have sufficient capital resources to complete additional acquisitions,
- successfully integrate acquired operations and assets,
- be able to manage effectively the growth and increased size,
- be successful in deploying idle or stacked rigs,
- be able to maintain the crews and market share attributable to operating drilling rigs acquired, or
- be successful in improving 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 could be dilutive to our existing stockholders. Also, continued growth could strain our management, operations, employees, and resources.

The Nature of our Business Operations Presents Inherent Risks of Loss that, if not Insured or Indemnified Against, Could Adversely Affect Patterson-UTI's 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 Patterson-UTI 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 $750,000 per occurrence deductible on our workers' compensation insurance coverage and a $1.0 million per occurrence deductible on our general liability insurance coverage. These levels of self-insurance expose us to increased operating costs and risks.

Violations of Environmental Laws and Regulations Could Materially Adversely Affect Patterson-UTI's 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 to Patterson-UTI of compliance with these laws and regulations could be substantial. Failure to comply with these requirements could subject Patterson-UTI 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. Patterson-UTI, as an owner and operator of land-based drilling rigs, 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 done 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 for 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 performing drilling services until the target depth is reached. We must also make significant up-front working capital commitments prior to receiving payment. 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 of Patterson-UTI and Thereby Affect the Related Purchase Price.

Patterson-UTI, as a Delaware corporation, is 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 of Patterson-UTI may 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.

We have Paid no Dividends on Our Common Stock and have no Plans to Pay Dividends.

We have not declared or paid cash dividends on our common shares in the past. We currently have no plan to declare or pay any cash dividends on our common stock in the foreseeable future. The terms of our existing credit facility limit payment of dividends without the prior written consent of the lenders.

PART II

Item 5. ***Market for Registrant's Common Equity and Related Stockholder Matters.***

Our common stock, par value $0.01 per share, is publicly traded on the Nasdaq National Market and is quoted under the symbol "PTEN." In December 2002, our common stock was added to the Nasdaq-100 Index and in November 2001, our common stock was added to the S&P MidCap 400 Index. Our common stock is also included in several other market indexes.

The following table sets forth the high and low sales prices of our common shares for the periods indicated:

	High	Low
2003:		
First quarter	$35.50	$27.09
Second quarter	36.97	31.80
Third quarter	32.28	25.15
Fourth quarter	33.93	25.67
2002:		
First quarter	$29.85	$18.87
Second quarter	34.60	26.83
Third quarter	29.78	20.63
Fourth quarter	33.97	23.96

As of December 31, 2003, there were approximately 300 holders of record and approximately 19,000 beneficial holders of our common shares.

We have not declared or paid cash dividends on our common shares in the past. We currently have no plan to declare or pay any cash dividends on our common stock in the foreseeable future. Instead, we currently intend to retain our earnings to support the operations and growth of our business. Any future cash dividends would depend on future earnings, capital requirements, financial condition, and other factors deemed relevant by the Board of Directors. In addition, the terms of our existing credit facility limit payment of dividends without the prior written consent of the lenders.

The following table summarizes as of December 31, 2003, certain information regarding equity compensation to our employees, officers, directors, and other persons under our equity compensation plans:

	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	5,279,021	$20.82	2,242,037
Equity compensation plans not approved by security holders(1)	858,737	$19.39	25,694
Total	6,137,758	$20.62	2,267,731

(1) The Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan was approved by the Company's Board of Directors in July 2001. The terms of the Plan provide for grants of stock options to eligible employees other than officers and directors of the Company. The total number of stock options that could be granted under the Plan was 1,000,000. 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 Company's common stock at the time of grant. The vesting schedule and term are set by the Compensation Committee of the Board of Directors.

Also in July 2001, the Company's Board of Directors approved option grants, not included in any of the Company's stock option plans, for two non-employee directors, each covering options to purchase 12,000 shares of the Company's common stock at an exercise price greater than the fair market value of the

Company's common stock on the grant date. The options vested in November 2001 and expire in November 2005.

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

The selected consolidated financial data of Patterson-UTI as of December 31, 2003, 2002, 2001, 2000, and 1999, 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. Historical financial statements as presented herein, have been restated to provide for the retroactive effect of the merger with UTI Energy Corp., on May 8, 2001.

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share amounts)				
Income Statement Data:					
Operating revenues:					
Drilling	$ 639,694	$410,295	$839,931	$512,998	$266,212
Pressure pumping	46,083	32,996	39,600	21,465	20,721
Drilling and completion fluids	69,230	69,943	94,456	32,053	11,686
Oil and natural gas	21,163	14,723	15,988	15,806	8,563
Other	—	—	—	—	184
Total	776,170	527,957	989,975	582,322	307,366
Operating costs and expenses:					
Drilling	475,224	318,201	487,343	384,840	224,590
Pressure pumping	26,184	19,802	21,146	13,403	12,219
Drilling and completion fluids	61,424	60,762	80,034	26,545	9,864
Oil and natural gas	4,808	3,956	5,190	4,872	2,500
Depreciation, depletion, and amortization	97,998	91,216	86,159	61,464	52,553
General and administrative	27,709	26,140	28,561	22,190	17,735
Bad debt expense	259	320	2,045	570	282
Merger costs	—	—	5,943	—	—
Restructuring and other charges	(2,452)	4,700	7,202	—	—
Other	(2,174)	(538)	(820)	(147)	(2,927)
Total	688,980	524,559	722,803	513,737	316,816
Operating income (loss)	87,190	3,398	267,172	68,585	(9,450)
Other income (expense)	967	441	(677)	(8,481)	(7,053)
Income (loss) before income taxes and cumulative effect of change in accounting principle	88,157	3,839	266,495	60,104	(16,503)
Income tax expense (benefit)	32,362	1,670	102,333	22,878	(4,766)
Income (loss) before cumulative effect of change in accounting principle	55,795	2,169	164,162	37,226	(11,737)

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share amounts)				
Cumulative effect of change in accounting principle, net of related income tax benefit of approximately $287	(469)	—	—	—	—
Net income (loss)	$ 55,326	$ 2,169	$164,162	$ 37,226	$(11,737)
Net income (loss) per common share:					
Basic:					
Income (loss) before cumulative effect of change in accounting principle	$ 0.69	$ 0.03	$ 2.15	$ 0.52	$ (0.18)
Cumulative effect of change in accounting principle	(0.01)	—	—	—	—
Net income (loss)	$ 0.68	$ 0.03	$ 2.15	$ 0.52	$ (0.18)
Diluted:					
Income (loss) before cumulative effect of change in accounting principle	$ 0.68	$ 0.03	$ 2.07	$ 0.50	$ (0.18)
Cumulative effect of change in accounting principle	(0.01)	—	—	—	—
Net income (loss)	$ 0.67	$ 0.03	$ 2.07	$ 0.50	$ (0.18)
Weighted average number of common shares outstanding:					
Basic	80,636	78,705	76,407	71,207	66,483
Diluted	82,286	81,252	79,197	74,841	66,483
Balance Sheet Data:					
Current assets	$ 308,060	$243,015	$199,458	$237,742	$106,091
Total assets	1,075,830	942,509	869,642	739,898	496,715
Current liabilities	108,447	75,152	89,286	110,443	60,930
Long-term debt	—	—	—	79,416	82,196
Stockholders' equity	820,071	737,556	687,142	481,299	309,695
Working capital	199,613	167,863	110,172	127,299	45,161

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.

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, 2003 our operating revenues consisted of the following (dollars in thousands):

	2003		2002		2001	
Contract drilling	$639,694	82%	$410,295	78%	$839,931	85%
Pressure pumping	46,083	6	32,996	6	39,600	4
Drilling and completion fluids	69,230	9	69,943	13	94,456	9
Oil and natural gas	21,163	3	14,723	3	15,988	2
	$776,170	100%	$527,957	100%	$989,975	100%

We provide our contract services to oil and natural gas operators throughout 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, New Mexico, Oklahoma, the Gulf Coast regions of Texas and Louisiana and the Gulf of Mexico. Our oil and natural gas operations are primarily focused in Texas, New Mexico 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 343 rigs, which we believe is the second largest drilling fleet 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 market share.

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 2003, our average number of rigs operating increased to 188 from 126 in 2002 and our average revenue per operating day increased to $9,300 from $8,930 in 2002. Primarily due to these improved operating results, we experienced an increase of approximately $53 million in net income in 2003.

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 also 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 15 of this Report.

Management believes that the liquidity of our balance sheet as of December 31, 2003, which includes approximately $200 million in working capital (including $100 million in cash), no long term debt and a $100 million undrawn line of credit, provides us with the ability to pursue acquisition opportunities, expand into new regions, make improvements to our assets and to 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 totaling $37.0 million at December 31, 2003, 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 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. However in June 2002 and October 2002, we acquired a total of 1,058,673 shares of common stock of TMBR/Sharp Drilling, Inc., a company whose stock is traded on the NASDAQ National Market System, for a total cost of $17.7 million.

Description of business — Based on publicly available information, we believe we are the second largest owner of land-based drilling rigs in North America. We conduct our contract drilling operations in Texas, New Mexico, Oklahoma, Louisiana, Mississippi, Colorado, Utah, Wyoming, and Western Canada. As of December 31, 2003, we owned 343 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 West Texas, Southeast New Mexico, South Texas, East Texas, Oklahoma, the Gulf Coast regions of Texas and 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 business operates primarily in producing regions in West Texas, Southeast New Mexico, South Texas and Mississippi.

The contract drilling business experienced increased demand for drilling services in 1997, 2000 and 2001. However, except for those periods and other occasional upturns, generally, there have been substantially more drilling rigs available than necessary to meet demand in most operational and geographic segments of the North American land drilling industry. As a result, drilling contractors have had difficulty sustaining profit margins.

In addition to adverse effects that future declines in demand could have on Patterson-UTI, 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, or
- 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, intangible assets, 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, including intangible 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 during the years 2003, 2002 or 2001.

Oil and natural gas properties — Oil and natural gas properties are accounted for using the successful efforts method of accounting. Exploration and development costs which result directly in the discovery of oil and natural gas reserves are capitalized to the appropriate well. Exploration costs which do not result directly in the discovery of 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. 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 petroleum engineer 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 our reserve 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 $1.4 million, $700,000 and $1.1 million for the years ended December 31, 2003, 2002 and 2001, respectively, is included in depreciation, depletion, and amortization in the accompanying financial statements.

Intangible assets — Intangible assets consist primarily of goodwill arising from business combinations (see Note 5 of Notes to Consolidated Financial Statements included as part of Item 8 of this Report). Intangible assets other than goodwill are amortized on a straight line basis over their estimated useful lives. Covenants not to compete are amortized over their underlying contractual lives of five years. Prior to 2002, goodwill, representing the excess of the purchase price over the estimated fair value of the net assets of the acquired business, was amortized over the period of expected benefit of 15 years. However, effective January 1, 2002, we adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," ("SFAS No. 142") which requires that we cease amortization of all intangible assets having indefinite useful economic lives. Such assets, including goodwill, are not to be amortized until their lives are determined to be finite, however, a recognized intangible asset with an indefinite useful life should be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. At December 31, 2003, we evaluated our goodwill and other intangible assets and determined that fair value had not decreased below carrying value and no adjustment to impair goodwill and other intangible assets was necessary in accordance with SFAS No. 142. With respect to our drilling and completion fluids business, the determination that no impairment existed was based on our expectations of improvement in the results of operations for that business segment. If the expected improvement in results does not occur, all or part of the goodwill and other intangible assets 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 this method, drilling revenues and costs related to a well in progress are recognized proportionately over the time it takes to drill the well. Percentage-of-completion is determined based upon the amount of expenses incurred through the measurement date as compared to total estimated expenses to be incurred drilling the well. 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, all drilling advances and costs related to a well in progress are deferred and recognized as revenues and expenses in the period the well is completed. Provisions for losses on incomplete or in-process wells are made when estimated total costs are expected to exceed estimated total revenues.

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

Key estimates used by management include:

- allowance for doubtful accounts,
- 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 — In 2001, we leased a 1981 Beech King-Air 90 airplane owned by SSI Oil and Gas, Inc., an entity beneficially owned 50% by Cloyce A. Talbott, Patterson-UTI's Chief Executive Officer, and directly owned 50% by A. Glenn Patterson, Patterson-UTI's President/Chief Operating Officer. Under the terms of the lease, we paid a monthly rental of $9,200, the costs of fuel, insurance, taxes, and maintenance of the aircraft. Such amounts totaled approximately $212,000 for the year ended December 31, 2001.

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 originated or acquired by Patterson-UTI. At December 31, 2003, affiliated persons were working interest owners in 236 of the 260 wells operated by Patterson-UTI. Sales of working interests are made by Patterson-UTI to reduce its economic risk in the properties. Generally, it is more efficient for Patterson-UTI to sell the working interests to these affiliated persons than to market them to unrelated third parties. 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 following table sets forth production revenues and joint interest costs of each of the affiliated persons during 2003 for all wells operated by Patterson-UTI in which they have working interests. 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, 2003. These activities resulted in a net receivable from the affiliated persons of approximately $17,000 at December 31, 2003 and a net payable to the affiliated persons of approximately $466,000 at December 31, 2002.

Name	Year Ended December 31, 2003 Production Revenues(1)	Joint Interest Costs(2)
Cloyce A. Talbott	$ 185,180	$ 85,244
Anita Talbott(3)	73,424	27,514
Jana Talbott, Executrix to the Estate of Steve Talbott(3)	2,633	3,467
Stan Talbott(3)	8,802	2,531
John Evan Talbott Trust(3)	2,880	1,066
Lisa Beck and Stacy Talbott(3)	737,445	503,017
SSI Oil & Gas, Inc.(4)	240,921	129,290
IDC Enterprises, Ltd.(5)	9,558,279	6,829,996
SSSL, Ltd.(6)(8)	—	1,177
Subtotal	10,809,564	7,583,302
A. Glenn Patterson	125,283	45,942
Glenn Patterson Family Limited Partnership(7)(8)	—	1,181
Robert Patterson(7)	8,423	3,348
Thomas M. Patterson(7)	8,423	3,348
Subtotal	142,129	53,819
Jonathan D. Nelson, Patterson-UTI's Chief Financial Officer	151,912	265,355
Total	$11,103,605	$7,902,476

(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) SSSL, Ltd. is a limited partnership in which children and grandchildren of Mr. Talbott are beneficiaries and Mr. Talbott is the general partner.

(7) Robert and Thomas M. Patterson are A. Glenn Patterson's adult children. The Glenn Patterson Family Limited Partnership is a partnership in which each of Mr. Patterson's children shares equally and Mr. Patterson is the manager.

(8) Revenues included in IDC Enterprises, Ltd. revenues.

In 2003, 2002 and 2001, we paid approximately $740,000, $279,000 and $387,000, 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 2003, we paid approximately $209,000 to Melco Services ("Melco") for dirt contracting services and $59,000 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.

Liquidity and Capital Resources

As of December 31, 2003, we had working capital of $199.6 million including cash and cash equivalents of $100.5 million. For 2003, our significant sources of cash flow were:

- $161.5 million derived from operations,
- $10.3 million from the exercise of stock options and warrants, and
- $4.5 million from the sale of certain property and equipment.

We used approximately $157.9 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.

In January 2003, we 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 an acquisition of assets and the purchase price was allocated among the assets acquired based on their estimated fair market values.

In February 2003, we 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.

In April 2003, we 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.

In May 2003, we 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.

In May 2003, the Company, Patterson-UTI Acquisition, LLC, a wholly-owned subsidiary of the Company ("Sub"), and TMBR/Sharp Drilling, Inc., a Texas corporation ("TMBR"), entered into an Agreement and Plan of Merger, as amended by Amendment No. 1 to Agreement and Plan of Merger, dated as of December 30, 2003, by and among the same parties (the "Merger Agreement"), pursuant to which, upon the satisfaction and completion of the conditions to the merger contained in the Merger Agreement, including approval of the Merger Agreement by at least two-thirds of the shareholders of TMBR, TMBR will merge with and into Sub with Sub being the surviving company. If the merger is completed, each issued and outstanding share of common stock, $.10 par value per share, of TMBR not owned directly or indirectly by the Company or TMBR or held by TMBR shareholders who validly exercise their dissenters' rights under Texas law, will be converted into the right to receive $9.09 in cash from the Company and 0.312166 of a share of common stock, $0.01 par value per share, of the Company (the "Company Common Stock"), for a total of approximately $40.4 million in cash and approximately 1.39 million shares of Company Common Stock based on the outstanding shares of TMBR common stock as of January 5, 2004. The Company currently intends to pay the cash portion of the merger consideration to TMBR shareholders out of funds available on hand and existing financing facilities. The TMBR shareholders' meeting is currently scheduled for February 11, 2004.

In November 2003, we 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.

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

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 reviewed relating to our business. The timing, size or success of any acquisition and the associated capital commitments are unpredictable. Over the longer term, should further 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, and either debt 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, 2003 and 2002

The following tables summarize operations by business segment for the twelve months ended December 31, 2003 and 2002:

Contract Drilling	Years Ended December 31, 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	$ 4,425	$ 3,987	11.0%
Depreciation and amortization	$ 84,379	$ 80,500	4.8%
Operating income	$ 75,666	$ 7,607	894.7%
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	$ 95,175	$ 68,516	38.9%

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

	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.

Pressure Pumping	Years Ended December 31, 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.

Drilling and Completion Fluids	Years Ended December 31, 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	$ 2,319	$ 2,216	4.6%
Operating loss	$(1,960)	$ (278)	605.0%
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.

Oil and Natural Gas Production and Exploration	Years Ended December 31, 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 and depletion	$ 7,082	$ 5,251	34.9%
Operating income	$ 7,784	$ 3,945	97.3%
Capital expenditures	$10,484	$ 6,357	64.9%
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.

Corporate and Other	Years Ended December 31, 2003	2002	% Change
	(Dollars in thousands)		
Selling, general, and administrative	$ 8,665	$9,038	(4.1)%
Bad debt expense	$ 259	$ 320	(19.1)%
Depreciation and amortization	$ 444	$ 446	(0.4)%
Other income	$ 2,174	$ 538	304.1%
Restructuring and other charges	$(2,452)	$4,700	N/A

In 2003, Restructuring and other charges 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 of Patterson-UTI. 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, Restructuring and other charges reflects a $4.7 million charge due to the financial failure of a workers' compensation insurance carrier we used from 1992 until March 2001.

Comparison of the years ended December 31, 2002 and 2001

The following tables summarize operations by business segment for the twelve months ended December 31, 2002 and 2001:

Contract Drilling	Years Ended December 31, 2002	2001	% Change
	(Dollars in thousands)		
Revenues	$410,295	$839,931	(51.2)%
Direct operating costs	$318,201	$487,343	(34.7)%
Selling, general, and administrative	$ 3,987	$ 5,277	(24.4)%
Depreciation and amortization	$ 80,500	$ 72,797	10.6%
Operating income	$ 7,607	$274,514	(97.2)%
Operating days	45,919	76,871	(40.3)%
Average revenue per operating day	$ 8.94	$ 10.93	(18.2)%
Average direct operating costs per operating day	$ 6.93	$ 6.34	9.3%
Number of owned rigs at end of period	324	319	1.6%
Average number of rigs owned during period	323	302	7.0%
Average rigs operating	126	211	(40.3)%
Rig utilization percentage	39%	70%	(44.3)%
Capital expenditures	$ 68,516	$150,788	(54.6)%

The following table illustrates the average market price of natural gas and our average rigs operating for each of the fiscal quarters in 2002 and 2001:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2002:				
Average natural gas price	$2.51	$3.41	$3.20	$4.31
Average rigs operating	117	119	127	140
2001:				
Average natural gas price	$6.23	$4.41	$2.78	$2.70
Average rigs operating	231	248	225	140

Our rig count began to decline in the third quarter of 2001 and continued until March 2002 when our rig count bottomed at 103 rigs (90 rigs in the U.S. and 13 rigs in Canada). The deterioration in our rig count was primarily the result of weakening natural gas prices through mid-February 2002. Natural gas prices then rebounded somewhat and our rig count improved marginally during the period from March through September 2002. In the fourth quarter of 2002, consistent with improved natural gas prices, our rig count continued to improve and averaged 140 rigs (132 rigs in the U.S. and 8 rigs in Canada).

The decreased operating results in 2002 were reflective of a significant decline in demand for our contract drilling services as evidenced by decreases in the number of operating days and average rig utilization. Increased competition during 2002 for available jobs resulted in downward pricing pressure and decreased operating revenues. Increased operating costs per operating day were primarily attributable to increased labor costs, including payroll expenses and workers' compensation insurance costs. Payroll expenses increased as experienced field personnel were retained despite the significant decline in our average rig utilization. Management believes this strategy is beneficial as it (1) retains experienced personnel and (2) facilitates our response to increased demand levels as industry conditions improve. General and administrative expenses decreased primarily as a result of reduced incentive compensation in 2002. Depreciation and amortization increased in 2002 primarily as a result of (1) significant capital expenditures in 2001 and 2002 to modify and upgrade our drilling fleet and (2) our acquisition of drilling rigs and related equipment from Cleere Drilling Company in December 2001.

Pressure Pumping	Years Ended December 31, 2002	2001	% Change
	(Dollars in thousands)		
Revenues	$32,996	$39,600	(16.7)%
Direct operating costs	$19,802	$21,146	(6.4)%
Selling, general, and administrative	$ 4,301	$ 3,910	10.0%
Depreciation	$ 2,803	$ 1,895	47.9%
Operating income	$ 6,090	$12,649	(51.9)%
Total jobs	3,796	4,609	(17.6)%
Average revenue per job	$ 8.69	$ 8.59	1.2%
Average direct operating costs per job	$ 5.22	$ 4.59	13.7%
Capital expenditures	$ 7,399	$ 7,756	(4.6)%

The decreases in revenues and expenses for our pressure pumping operations were primarily attributable to industry conditions, as discussed in "Contract Drilling" above. Expansion of our pressure pumping services in 2001 and 2002 into the Appalachian regions of Kentucky and West Virginia resulted in increased depreciation and selling, general, and administrative expenses in 2002. Additionally, direct operating costs per job increased in 2002 since a portion of direct operating costs remain constant despite fluctuating activity levels.

Drilling and Completion Fluids	Years Ended December 31, 2002	2001	% Change
	(Dollars in thousands)		
Revenues	$69,943	$94,456	(26.0)%
Direct operating costs	$60,762	$80,034	(24.1)%
Selling, general, and administrative	$ 7,243	$ 7,936	(8.7)%
Depreciation and amortization	$ 2,216	$ 2,644	(16.2)%
Operating income (loss)	$ (278)	$ 3,842	N/A
Total jobs	1,457	1,920	(24.1)%
Average revenue per job	$ 48.00	$ 49.20	(2.4)%
Average direct operating costs per job	$ 41.70	$ 41.68	0.0%
Capital expenditures	$ 1,571	$ 4,937	(68.2)%

The decrease in revenues for our drilling and completion fluids operations were primarily attributable to industry conditions, as discussed in "Contract Drilling" above, and the resulting 24.1% decline in the number of jobs completed. Direct operating costs per job increased despite reduced activity levels due to a portion of the segment's operating expenses being fixed in nature. The 8.7% decrease in selling, general, and administrative expense is primarily the result of reduced employee incentive compensation in 2002.

Oil and Natural Gas Production and Exploration	Years Ended December 31, 2002	2001	% Change
	(Dollars in thousands)		
Revenues	$14,723	$15,988	(7.9)%
Direct operating costs	$ 3,956	$ 5,190	(23.8)%
Selling, general, and administrative	$ 1,571	$ 1,537	2.2%
Depreciation and depletion	$ 5,251	$ 8,505	(38.3)%
Operating income	$ 3,945	$ 756	421.8%
Capital expenditures	$ 6,357	$ 7,956	(20.1)%
Average net daily oil production (Bbls)	794	739	7.4%
Average net daily gas production (Mcf)	5,109	4,654	9.8%
Average oil sales price (per Bbl)	$ 25.02	$ 24.88	0.6%
Average gas sales price (per Mcf)	$ 2.91	$ 4.12	(29.4)%

Decreased revenues are attributable to lower average prices received from sales of natural gas. Direct operating costs declined in 2002 primarily due to the divestiture of marginally productive wells in 2002, thus reducing lease operating costs. Depreciation and depletion declined in 2002 primarily due to significant decreased depletion expense in 2002 as a result of increased commodity prices at December 31, 2002.

Corporate and Other	Years Ended December 31, 2002	2001	% Change
	(Dollars in thousands)		
Selling, general, and administrative	$9,038	$9,901	(8.7)%
Bad debt expense	$ 320	$2,045	(84.4)%
Depreciation and amortization	$ 446	$ 318	40.3%
Other income	$ 538	$ 820	(34.4)%
Merger costs	$ —	$5,943	N/A
Restructuring and other charges	$4,700	$7,202	(34.7)%
Capital expenditures	$ —	$5,320	N/A

The decrease in selling, general, and administrative expense of 8.7% primarily relates to reduced employee incentive compensation in 2002. Restructuring and other charges reflect a $4.7 million charge taken in the second quarter of 2002 due to the financial failure of a workers' compensation insurance carrier we used from 1992 until March 2001. Merger costs and restructuring and other charges in 2001 include an aggregate of $13.1 million for professional fees, severance and related expenses, closing of duplicate operational facilities and costs to amend our credit facilities associated with the merger with UTI.

Income Taxes

	Years Ended December 31, 2003	2002	2001
	(Dollars in thousands)		
Income before income tax	$88,157	$3,839	$266,495
Income tax expense	32,362	1,670	102,333
Effective tax rate	36.7%	43.5%	38.4%

Net operating losses were fully utilized in 2001 and our remaining alternative minimum tax credit of $602,000 may be carried forward indefinitely. Other deferred tax assets consist primarily of various allowance accounts and tax deferred expenses expected to generate a future tax benefit of approximately $15.8 million.

Our effective income tax rate of 36.7% for 2003 is primarily attributable to a federal rate of 35.0% and a state income tax rate of 1.5%. The impact of permanent differences was not significant in 2003. The significance of the impact of the permanent differences of approximately 6.0% to our effective income tax rate in 2002 was largely attributable to our reduced 2002 pretax earnings.

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 $17.3 million, $23.5 million, and $14.6 million for 2003, 2002, and 2001, respectively.

Volatility of Oil and Natural Gas Prices

Our revenue, profitability, and future rate of growth are substantially dependent upon prevailing prices for oil and natural gas, with respect to all of our operating segments. Historically, oil and natural gas prices and markets have been volatile. Prices are affected by market supply and demand factors as well as actions of state and local agencies, the United States and foreign governments, and international cartels. 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 to $5.45 in 2003 compared to $3.36 in 2002, resulting in an increase in demand for our drilling services. Our average number of rigs operating increased to 188 in 2003 from 126 in 2002. 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 contract drilling business experienced increased demand for drilling services in 1997, 2000 and 2001. However, except for those periods and other occasional upturns, generally, there have been substantially more drilling rigs available than necessary to meet demand in most operational and geographic segments of the North American land drilling industry. 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 Standards No. 142, "Goodwill and Other Intangible Assets," ("SFAS No. 142") in June 2001. SFAS No. 142 supersedes APB Opinion No. 17, "Intangible Assets." Under the provisions of SFAS No. 142, which the Company adopted on January 1, 2002, goodwill is no longer amortized but is subject to an annual impairment test. During the year ended December 31, 2001, goodwill amortization totaled approximately $4.7 million.

The FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," ("SFAS No. 143") in June 2001. SFAS No. 143 addresses financial accounting requirements for retirement obligations associated with tangible long-lived assets. The Company adopted SFAS No. 143 in January 2003. As a result, a charge of $469,000 (net of tax) was recorded as a cumulative effect of a change in accounting principle during 2003. The change relates to the cost associated with the future abandonment of oil and natural gas properties. The related effect to basic and diluted earnings per share as a result of the change in accounting principle was a decrease of $0.01 per share for the twelve months ended December 31, 2003.

The FASB issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," ("SFAS No. 145") in April 2002. SFAS No. 145 amends existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The provisions of SFAS No. 145, which the Company adopted January 1, 2003, did not have a material impact on the Company's consolidated financial statements.

The FASB issued Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," ("SFAS No. 146") in June 2002. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. The adoption of SFAS No. 146 did not have a material impact on the Company's consolidated financial statements.

The FASB issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation," ("SFAS No. 148") in December 2002. SFAS No. 148 amends the disclosure requirements of Statement of Financial Accounting Standards No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The provisions of SFAS No. 148, which the Company adopted on January 1, 2003, did not have a material impact on the Company's consolidated financial statements (see Note 12 of Notes to Consolidated Financial Statements).

The FASB issued Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," ("SFAS No. 149") in April 2003. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149 is effective for existing contracts and new contracts entered into after June 30, 2003. The provisions of SFAS No. 149, which the Company adopted on July 1, 2003, did not have a material impact on the Company's consolidated financial statements.

The FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," ("SFAS No. 150") in May 2003. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The Company has no financial instruments which are subject to SFAS No. 150.

The FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements, Including Guarantees of Indebtedness of Others," ("FIN 45") which the Company adopted effective January 1, 2003. FIN 45 requires that upon issuance of certain types of guarantees, a guarantor recognize and account for the fair value of the guarantee as a liability. FIN 45 contains exclusions to this requirement, including the exclusion of a parent's guarantee of its subsidiaries' debt to a third party. The adoption of FIN 45 did not have a material impact on the Company's consolidated financial statements.

The FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities," ("FIN 46") which addresses the consolidation of variable interest entities ("VIEs") by business enterprises that are the primary beneficiaries. A VIE is an entity that does not have sufficient equity investment at risk to permit it to finance its activities without additional subordinated financial support, or whose equity investors lack the characteristics of a controlling financial interest. The primary beneficiary of a VIE is the enterprise that has the majority of the risks or rewards associated with the VIE. The Company believes it has no interests in VIEs that will require disclosure or consolidation under FIN 46.

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 1.75% to 2.75%. The applicable rate above LIBOR (1.75% at

December 31, 2003) is based upon our trailing twelve-month earnings before interest expense, income taxes and depreciation, depletion and amortization expense. 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 ten 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.*

As of the end of the period covered by this Annual Report on Form 10-K, the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934) was evaluated by our management, with the participation of our Chief Executive Officer, Cloyce A. Talbott (principal executive officer), and our Vice President, Chief Financial Officer, Secretary and Treasurer, Jonathan D. Nelson (principal financial officer). Messrs. Talbott and Nelson have concluded that our disclosure controls and procedures are effective, as of the end of the period covered by this Report, to help ensure that information we are required to disclose in reports that we file with the SEC is accumulated and communicated to management and recorded, processed, summarized and reported within the time periods prescribed by the SEC.

There were no changes in our internal control over financial reporting that occurred during our last fiscal quarter (the quarter ended December 31, 2003) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART III

The information required by Part III is omitted from this Report because Patterson-UTI 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.***

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, Financial Statement Schedules and Reports on Form 8-K.***

(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	Agreement and Plan of Merger, dated as of May 26, 2003, by and among Patterson-UTI Energy, Inc., Patterson-UTI Acquisition, LLC and TMBR/Sharp Drilling, Inc.(1)
2.2	Amendment No. 1 to Agreement and Plan of Merger, dated as of December 30, 2003, by and among Patterson-UTI Energy, Inc., Patterson-UTI Acquisition, LLC and TMBR/Sharp Drilling, Inc.(2)
3.1	Restated Certificate of Incorporation, as amended.(3)
3.2	Amended and Restated Bylaws.(4)
4.1	Rights Agreement dated January 2, 1997, between Patterson Energy, Inc. and Continental Stock Transfer & Trust Company.(5)
4.2	Amendment to Rights Agreement dated as of October 23, 2001.(6)
4.3	Restated Certificate of Incorporation, as amended (See Exhibit 3.1)
4.4	Registration Rights Agreement with Bear, Stearns and Co. Inc., dated March 25, 1994, as assigned by REMY Capital Partners III, L.P.(4)
4.5	Patterson-UTI Energy, Inc. 1993 Stock Incentive Plan, as amended.(7)*
4.6	Patterson-UTI Energy, Inc. Non-Employee Directors' Stock Option Plan, as amended.(8)*
4.7	Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan.(9)*
4.8	Patterson-UTI Energy, Inc. Amended and Restated 1997 Long-Term Incentive Plan.(3)*
4.9	Amended and Restated Patterson-UTI Energy, Inc. Non-Employee Director Stock Option Plan.(3)*
4.10	Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan.(10)*
4.11	1997 Stock Option Plan of DSI Industries, Inc.(11)*
4.12	Stock Option Agreement dated July 20, 2001 between Patterson-UTI Energy, Inc. and Kenneth R. Peak (a non-employee director of Patterson-UTI Energy, Inc.).(4)*
10.1	For additional material contracts, see Exhibits 4.1, 4.2 and 4.4 through 4.11.
10.2	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.*
10.3	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.*
10.4	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.*
10.5	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.*
10.6	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.*
10.7	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.*
10.8	Model Form Operating Agreement.(12)

10.9 Form of Drilling Bid Proposal and Footage Drilling Contract.(12)

10.10 Form of Turnkey Drilling Agreement.(12)

14.1 Patterson-UTI Energy, Inc. Code of Business Conduct and Ethics for Senior Financial Executives.

21.1 Subsidiaries of the Registrant.

23.1 Consent of Independent Accountants — PricewaterhouseCoopers LLP.

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.

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(1) Incorporated herein by reference to Exhibit 2.1 to Form 8-K of TMBR/Sharp Drilling, Inc. filed on May 27, 2003.

(2) Incorporated herein by reference to Exhibit 2.1 to Form 8-K filed on December 31, 2003.

(3) Incorporated herein by reference to Item 6, "Exhibits and Reports on Form 8-K" to Form 10-Q for the quarterly period ended June 30, 2003, filed on July 28, 2003.

(4) Incorporated herein by reference to Item 14, "Exhibits, Financial Statement Schedules and Reports on Form 8-K" to Annual Report on Form 10-K for the fiscal year ended December 31, 2001, filed on March 19, 2002.

(5) Incorporated herein by reference to Item 2, "Exhibits" to Registration Statement on Form 8-A filed on January 14, 1997.

(6) Incorporated herein by reference to Item 6, "Exhibits and Reports on Form 8-K" to Form 10-Q for the quarterly period ended September 30, 2001, filed on October 31, 2001.

(7) Incorporated herein by reference to Item 8, "Exhibits" to Registration Statement on Form S-8 (File No. 333-47917) filed on March 13, 1998.

(8) Incorporated herein by reference to Item 8, "Exhibits" to Registration Statement on Form S-8 (File No. 333-39471) filed on November 4, 1997.

(9) Incorporated herein by reference to Item 8, "Exhibits" to Post-Effective Amendment No. 1 to Registration Statement on Form S-8 (File No. 333-60470) filed on November 27, 2002.

(10) Incorporated herein by reference to Item 8, "Exhibits" to Post-Effective Amendment No. 1 to Registration Statement on Form S-8 (File No. 333-60466) filed on July 25, 2001.

(11) Incorporated herein by reference to Item 8, "Exhibits" to Post-Effective Amendment No. 1 to Registration Statement on Form S-8 (File No. 333-60470) filed on July 25, 2001.

(12) Incorporated herein by reference to Item 27, "Exhibits" to Registration Statement on Form SB-2 (File No. 33-68058-FW) filed on August 30, 1993.

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

(b) *Reports on Form 8-K.*

On December 31, 2003, the Company filed a Current Report on Form 8-K, dated December 30, 2003, reporting the amendment to its Agreement and Plan of Merger with TMBR/Sharp Drilling, Inc. to extend the date under which the parties have certain rights of termination to February 14, 2004 from December 31, 2003.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Patterson-UTI Energy, Inc. and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule on page S-1 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 schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 Notes 1 and 5 to the consolidated financial statements, in accordance with Statement of Financial Accounting Standards No. 142 "Goodwill and Other Intangible Assets" beginning in 2002 the Company no longer amortizes goodwill.

PricewaterhouseCoopers LLP

Houston, Texas
January 30, 2004

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 100,483	$ 82,154
Accounts receivable, net of allowance for doubtful accounts of $2,133 and $3,144 at December 31, 2003 and 2002, respectively	156,345	99,014
Federal and state income taxes receivable	12,667	24,719
Inventory	15,206	15,323
Deferred tax assets	16,449	15,290
Other	6,910	6,515
Total current assets	308,060	243,015
Property and equipment, at cost, net	693,631	627,734
Goodwill and other intangible assets, net	51,179	51,313
Investment in equity securities	20,274	17,707
Other	2,686	2,740
Total assets	$1,075,830	$942,509
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 41,093	$ 30,618
Accrued revenue distributions	8,545	6,266
Other	6,743	2,755
Accrued expenses	52,066	35,513
Total current liabilities	108,447	75,152
Deferred tax liabilities	143,490	127,006
Other	3,822	2,795
Total liabilities	255,759	204,953
Commitments and contingencies	—	—
Stockholders' equity:		
Preferred stock, par value $.01; authorized 1,000,000 shares, no shares issued	—	—
Common stock, par value $.01; authorized 200,000,000 shares with 82,483,148 and 81,576,674 issued and 80,976,600 and 80,070,126 outstanding at December 31, 2003 and 2002, respectively	825	816
Additional paid-in capital	506,018	489,201
Retained earnings	316,329	261,003
Accumulated other comprehensive income (loss)	8,554	(1,809)
Treasury stock, at cost, 1,506,548 shares	(11,655)	(11,655)
Total stockholders' equity	820,071	737,556
Total liabilities and stockholders' equity	$1,075,830	$942,509

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31, 2003	2002	2001
	(In thousands, except per share data)		
Operating revenues:			
Drilling	$639,694	$410,295	$839,931
Pressure pumping	46,083	32,996	39,600
Drilling and completion fluids	69,230	69,943	94,456
Oil and natural gas, sales	19,058	12,738	13,842
Oil and natural gas, well operation fees	2,105	1,985	2,146
	776,170	527,957	989,975
Operating costs and expenses:			
Drilling	475,224	318,201	487,343
Pressure pumping	26,184	19,802	21,146
Drilling and completion fluids	61,424	60,762	80,034
Oil and natural gas, operating and production	4,276	3,672	4,334
Oil and natural gas, third party production	532	284	856
Depreciation, depletion, and amortization	97,998	91,216	86,159
General and administrative (includes $1,213, $1,281 and $1,268 in 2003, 2002 and 2001, respectively, incurred on behalf of third party working interest owners)	27,709	26,140	28,561
Bad debt expense	259	320	2,045
Merger costs	—	—	5,943
Restructuring and other charges	(2,452)	4,700	7,202
Other	(2,174)	(538)	(820)
	688,980	524,559	722,803
Operating income	87,190	3,398	267,172
Other income (expense):			
Interest income	1,116	1,110	2,080
Interest expense	(292)	(532)	(3,142)
Other	143	(137)	385
	967	441	(677)
Income before income taxes and cumulative effect of change in accounting principle	88,157	3,839	266,495
Income tax expense (benefit):			
Current	15,088	(21,878)	87,773
Deferred	17,274	23,548	14,560
	32,362	1,670	102,333
Income before cumulative effect of change in accounting principle	55,795	2,169	164,162
Cumulative effect of change in accounting principle, net of related income tax benefit of approximately $287	(469)	—	—
Net income	$ 55,326	$ 2,169	$164,162
Net income per common share:			
Basic:			
Income before cumulative effect of change in accounting principle	$ 0.69	$ 0.03	$ 2.15
Cumulative effect of change in accounting principle	(0.01)	—	—
Net income	$ 0.68	$ 0.03	$ 2.15
Diluted:			
Income before cumulative effect of change in accounting principle	$ 0.68	$ 0.03	$ 2.07
Cumulative effect of change in accounting principle	(0.01)	—	—
Net income	$ 0.67	$ 0.03	$ 2.07
Weighted average number of common shares outstanding:			
Basic	80,636	78,705	76,407
Diluted	82,286	81,252	79,197

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

PATTERSON-UTI ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common stock		Additional		Accumulated other		
	Number of Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (loss)	Treasury Stock	Total
				(In thousands)			
December 31, 2000	76,250	$763	$397,489	$ 94,672	$ 30	$(11,655)	$481,299
Issuance of common stock	1,260	12	31,405	—	—	—	31,417
Issuance of stock purchase warrant	—	—	2,600	—	—	—	2,600
Exercise of stock purchase warrants	121	1	1,819	—	—	—	1,820
Exercise of stock options	832	8	4,237	—	—	—	4,245
Tax benefit related to exercise of stock options	—	—	3,925	—	—	—	3,925
Foreign currency translation	—	—	—	—	(2,326)	—	(2,326)
Net income	—	—	—	164,162	—	—	164,162
December 31, 2001	78,463	784	441,475	258,834	(2,296)	(11,655)	687,142
Issuance of common stock	650	7	16,933	—	—	—	16,940
Exercise of stock options and warrants	2,464	25	15,714	—	—	—	15,739
Tax benefit related to exercise of stock options	—	—	15,079	—	—	—	15,079
Foreign currency translation	—	—	—	—	457	—	457
Change in unrealized gain on securities, net of tax	—	—	—	—	30	—	30
Net income	—	—	—	2,169	—	—	2,169
December 31, 2002	81,577	816	489,201	261,003	(1,809)	(11,655)	737,556
Exercise of stock options and warrants	906	9	10,277	—	—	—	10,286
Tax benefit related to exercise of stock options	—	—	6,540	—	—	—	6,540
Foreign currency translation	—	—	—	—	8,773	—	8,773
Change in unrealized gain on securities, net of tax	—	—	—	—	1,590	—	1,590
Net income	—	—	—	55,326	—	—	55,326
December 31, 2003	82,483	$825	$506,018	$316,329	$ 8,554	$(11,655)	$820,071

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

	Years ended December 31, 2003	2002	2001
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 55,326	$ 2,169	$164,162
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, and amortization	97,998	91,216	86,159
Provision for bad debts	259	320	2,045
Deferred income tax expense	17,274	23,548	14,560
Tax benefit related to exercise of stock options	6,540	15,079	3,925
Gain on sale of assets	(2,174)	(538)	(648)
Changes in operating assets and liabilities:			
Accounts receivable	(55,791)	34,565	6,648
Federal income taxes receivable	10,919	(23,216)	796
Inventory and other current assets	(196)	(222)	(355)
Accounts payable	12,322	(11,079)	(33,174)
Accrued expenses	14,026	(771)	12,430
Other liabilities	5,015	362	(2,542)
Net cash provided by operating activities	161,518	131,433	254,006
Cash flows from investing activities:			
Acquisitions, net of cash acquired	(40,832)	—	(40,546)
Purchases of property and equipment	(117,095)	(83,843)	(172,850)
Proceeds from sales of property and equipment	4,548	1,813	742
Purchase of investment equity securities	—	(17,659)	—
Change in other assets	34	1,097	(1,101)
Net cash used in investing activities	(153,345)	(98,592)	(213,755)
Cash flows from financing activities:			
Proceeds from issuance of notes payable	—	—	9,760
Payments of notes payable	—	—	(89,176)
Proceeds from exercise of stock options and warrants	10,286	15,739	6,065
Net cash provided by (used in) financing activities	10,286	15,739	(73,351)
Net increase (decrease) in cash and cash equivalents	18,459	48,580	(33,100)
Effect of exchange rate changes on cash	(130)	(10)	(232)
Cash and cash equivalents at beginning of year	82,154	33,584	66,916
Cash and cash equivalents at end of year	$ 100,483	$ 82,154	$ 33,584
Supplemental disclosure of cash flow information:			
Net cash received (paid) during the year for:			
Interest	$ (292)	$ (532)	$ (3,142)
Income taxes	2,730	13,492	(81,802)

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:

During March 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 650,000 shares of common stock valued at $26.06 per share. 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.

During 2001 the Company acquired Jones Drilling Corporation and certain assets of three other entities affiliated with Jones Drilling Corporation for $33.0 million, drilling rigs and related equipment from Cleere Drilling Company for an aggregate purchase price of $25.8 million and six drilling rigs through three separate transactions for $15.7 million. Of the $74.6 million, approximately $40.5 million was paid in cash as follows:

	(in thousands)
Purchase price	$ 74,563
Less non-cash items:	
Common stock issued	(31,417)
Warrants issued	(2,600)
Total cash paid	$ 40,546

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 and basis of presentation follows:

Description of business — Patterson-UTI Energy, Inc. and 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. The Company owns 343 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 West Texas, Southeast New Mexico, South Texas, East Texas, Oklahoma, the Gulf Coast regions of Texas and 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, Southeast New Mexico, South Texas and Mississippi.

Basis of presentation — The consolidated financial statements of Patterson-UTI Energy, Inc. and its wholly-owned subsidiaries have been prepared to give retroactive effect to the merger between Patterson Energy, Inc. ("Patterson") and UTI Energy Corp. ("UTI") 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.

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.

Management estimates — The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those 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 this method, drilling revenues and costs related to a well in progress are recognized proportionately over the time it takes to drill the well. Percentage-of-completion is determined based upon the amount of expenses incurred through the measurement date as compared to total estimated expenses to be incurred drilling the well. 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 advances and costs related to a well in progress are deferred and recognized as revenues and expenses in the period the well is completed. Provisions for losses on incomplete or in-process wells are made when estimated total costs are expected to exceed estimated total revenues.

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 are defined below.

	Useful Lives (years)
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 directly 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 directly 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 petroleum engineer 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 our reserve 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, then costs related to that property are expensed. Impairment expense is included in depreciation, depletion, and amortization in the accompanying financial statements.

Intangible assets — Intangible assets consist primarily of goodwill arising from business combinations (see Note 5). Intangible assets other than goodwill are amortized on a straight line basis over their estimated useful lives. Covenants not to compete are amortized over their underlying contractual lives of five years. Prior to 2002, goodwill, representing the excess of the purchase price over the estimated fair value of the net assets of the acquired business, was amortized over the period of expected benefit of 15 years. However, effective January 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," ("SFAS No. 142") which requires that the Company cease amortization of all intangible assets having indefinite useful economic lives. Such assets, including goodwill, are not to be amortized until their lives are determined to be finite, however, a recognized intangible asset with an indefinite useful life should be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. At December 31, 2003, the Company evaluated its goodwill and other intangible assets and determined that fair value had not decreased below carrying value and no adjustment to impair goodwill and other intangible assets was necessary in accordance with SFAS No. 142. With respect to the Company's drilling and completion fluids business, the determination that no impairment existed was based on the Company's expectations of improvement in the results of operations for that business segment. If the expected improvement in results does not occur, all or part of the goodwill and other intangible assets 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 2003, 2002 and 2001 (in millions):

	2003	2002	2001
Depreciation expense	$90.9	$85.8	$72.6
Depletion expense	5.6	4.4	7.3
Amortization expense	0.1	0.3	5.2
Impairment of oil and natural gas properties	1.4	0.7	1.1
Total	$98.0	$91.2	$86.2

Maintenance and repairs — Maintenance and repairs are charged to expense when incurred. Renewals and betterments which extend the life or improve existing properties 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 — In accordance with Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities," ("SFAS No. 115") investments in Available-for-Sale equity securities are recorded at fair value. Unrealized gains and losses on such investments, net of tax, are included in accumulated other comprehensive income (loss) in our consolidated balance sheets as of December 31, 2003 and 2002, and are shown as a separate component of stockholders' equity (see Notes 3 and 6).

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") in its Consolidated Statements of Income. 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, 2003, 2002, and 2001, dilutive securities, consisting of certain stock options and warrants (See Note 12) included in the calculation of Diluted EPS were 1.7 million shares, 2.5 million shares, and 2.8 million shares, respectively. At December 31, 2003, 2002, and 2001, there were potentially dilutive securities of 930,000, 328,500, and 490,000, 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 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. 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 — The Company grants stock options to employees and non-employee directors under stock-based incentive compensation plans, (the "Plans"). The Company accounts for all stock-based employee compensation plans under the recognition and measurement provisions of APB Opinion No. 25, "Accounting for Stock Issued to Employees," ("APB No. 25") and related interpretations. Under APB No. 25, no stock-based employee compensation cost is reflected in net income, as all options granted under those plans 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 earnings per share as if the company had applied the fair value recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation," ("SFAS No. 123") to stock-based employee compensation:

	Years Ended December 31,		
	2003	2002	2001
	(In thousands, except per share amounts)		
Net income, as reported	$ 55,326	$ 2,169	$164,162
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects(1)	(10,506)	(5,296)	(7,053)
Pro forma net income (loss)	$ 44,820	$(3,127)	$157,109
Earnings (loss) per share:			
Basic, as reported	$ 0.68	$ 0.03	$ 2.15
Basic, pro forma	$ 0.56	$ (0.04)	$ 2.06
Diluted, as reported	$ 0.67	$ 0.03	$ 2.07
Diluted, pro forma	$ 0.54	$ (0.04)	$ 1.98
Weighted-average fair value per share of options granted(1)	$ 15.33	$ 15.19	$ 9.97

(1) See Note 12 for additional information regarding the computations presented here.

The FASB issued Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation," ("SFAS No. 148") in December 2002. SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The provisions of SFAS No. 148, which the Company adopted on January 1, 2003, did not have a material impact on the Company's consolidated financial statements (see Note 12).

Statement of cash flows — For purposes of reporting cash flows, cash and cash equivalents include cash on deposit and unrestricted certificates of deposit with original maturities of 90 days or less.

Recently Issued Accounting Standards — The Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," ("SFAS No. 142") in June 2001. SFAS No. 142 supersedes APB Opinion No. 17, "Intangible Assets." Under the provisions of SFAS No. 142, which the Company adopted on January 1, 2002, goodwill is no longer amortized but is subject to an annual impairment test. During the year ended December 31, 2001, goodwill amortization totaled approximately $4.7 million.

The FASB issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," ("SFAS No. 143") in June 2001. SFAS No. 143 addresses financial accounting requirements for retirement obligations associated with tangible long-lived assets. The Company adopted SFAS No. 143 in January 2003. As a result, a charge of $469,000 (net of tax) was recorded as a cumulative effect of a change in accounting principle during 2003. The change relates to the cost associated with the future abandonment of oil and natural gas properties. The related effect to basic and diluted earnings per share as a result of the change in accounting principle was a decrease of $0.01 per share for the twelve months ended December 31, 2003.

The FASB issued Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," ("SFAS No. 145") in April 2002. SFAS No. 145 amends existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The provisions of SFAS No. 145, which the Company adopted January 1, 2003, did not have a material impact on the Company's consolidated financial statements.

The FASB issued Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," ("SFAS No. 146") in June 2002. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. The adoption of SFAS No. 146 did not have a material impact on the Company's consolidated financial statements.

The FASB issued Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," ("SFAS No. 149") in April 2003. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149 is effective for existing contracts and new contracts entered into after June 30, 2003. The provisions of SFAS No. 149, which the Company adopted on July 1, 2003, did not have a material impact on the Company's consolidated financial statements.

The FASB issued Statement of Financial Accounting Standards No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," ("SFAS No. 150") in May 2003. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The Company has no financial instruments which are subject to SFAS No. 150.

The FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements, Including Guarantees of Indebtedness of Others," ("FIN 45") which the Company adopted effective January 1, 2003. FIN 45 requires that upon issuance of certain types of guarantees, a guarantor recognize and account for the fair value of the guarantee as a liability. FIN 45 contains exclusions to this requirement, including the exclusion of a parent's guarantee of its subsidiaries' debt to a third party. The adoption of FIN 45 did not have a material impact on the Company's consolidated financial statements.

The FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities," ("FIN 46") which addresses the consolidation of variable interest entities ("VIEs") by business enterprises that are the primary beneficiaries. A VIE is an entity that does not have sufficient equity investment at risk to permit it to finance its activities without additional subordinated financial support, or whose equity investors lack the characteristics of a controlling financial interest. The primary beneficiary of a VIE is the enterprise that has the majority of the risks or rewards associated with the VIE. The Company believes it has no interests in VIEs that will require disclosure or consolidation under FIN 46.

Reclassifications — Certain reclassifications have been made to the 2002 and 2001 consolidated financial statements in order for them to conform with the 2003 presentation.

2. Mergers and Acquisitions

TMBR/Sharp Drilling, Inc. — On May 26, 2003, the Company, Patterson-UTI Acquisition, LLC, a wholly-owned subsidiary of the Company ("Sub"), and TMBR/Sharp Drilling, Inc., a Texas corporation ("TMBR"), entered into an Agreement and Plan of Merger, as amended by Amendment No. 1 to Agreement and Plan of Merger dated as of December 30, 2003, by and among the same parties (the "Merger

Agreement"), pursuant to which, upon the satisfaction and completion of the conditions to the merger contained in the Merger Agreement, including approval of the Merger Agreement by at least two-thirds of the shareholders of TMBR, TMBR will merge with and into Sub with Sub being the surviving company. If the merger is completed, each issued and outstanding share of common stock, $.10 par value per share, of TMBR not owned directly or indirectly by the Company or TMBR or held by TMBR shareholders who validly exercise their dissenters' rights under Texas law, will be converted into the right to receive $9.09 in cash from the Company and 0.312166 of a share of common stock, $0.01 par value per share, of the Company (the "Company Common Stock"), for a total of approximately $40.4 million in cash and approximately 1.39 million shares of Company Common Stock based on the outstanding shares of TMBR common stock as of January 5, 2004. The Company currently intends to pay the cash portion of the merger consideration to TMBR shareholders out of funds available on hand and existing financing facilities. The TMBR shareholders' meeting is scheduled for February 11, 2004.

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 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 650,000 shares of common stock valued at $26.06 per share. 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.

2001 Merger and Acquisitions

Cleere Drilling Company — On December 21, 2001, the Company acquired 17 drilling rigs and related equipment from Cleere Drilling Company for an aggregate purchase price of $25.8 million. The purchase price consisted of $13.5 million cash plus 450,000 shares of its common stock and warrants to acquire an additional 325,000 shares of common stock at an exercise price of $26.75 per share. The common stock was recorded at $21.55 per share and the warrants were valued at $8.00 per underlying share of the Company's common stock using the Black-Scholes option valuation model. 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.

UTI Energy Corp. — On February 4, 2001, Patterson entered into an Agreement and Plan of Merger with UTI providing for the merger of the two entities. On May 8, 2001, the stockholders of each company approved the merger and the merger was consummated. Each outstanding share of UTI common stock was converted into one share of Patterson common stock and each option or warrant then outstanding representing the right to receive UTI common stock was converted into the right to purchase Patterson-UTI common stock on an equivalent basis. A total of 37,782,135 shares of common stock was issued pursuant to the merger and an additional 3,621,079 shares were reserved for issuance under the then outstanding UTI stock option plans. Additionally, the stockholders of Patterson approved an increase in the authorized shares of common stock from 50 million to 200 million and a name change to "Patterson-UTI Energy, Inc." Pursuant to the terms of the Agreement and Plan of Merger and resolutions adopted by the Company's Board of Directors, the Company has agreed to indemnify its directors and officers and former directors and officers of UTI for acts or omissions occurring at or prior to the merger with UTI or for certain liabilities that might occur as a result of the merger with UTI.

The Company incurred $13.1 million in expenses related to the merger. The expenses consisted of $5.9 million in merger costs which were primarily related to professional fees paid to investment banking firms, attorneys, accountants and commercial printers for their professional services rendered and $7.2 million in restructuring costs and related charges incurred as a result of the following:

- severance costs and related expenses of $2.8 million,
- closing of duplicate operational facilities of $1.6 million,
- costs of $1.4 million incurred in connection with changes to the Company's credit facilities (see Note 9), and
- fees and expenses related to the transfer of licenses and leaseholds, and in some instances the impairment of such leaseholds, the combination or cancellation of various service contracts and the renegotiation of certain insurance policies of $1.4 million.

The merger was treated as a reorganization within the meaning of Section 368(a) of the Internal Revenue Code of 1986, as amended, and was accounted for as a pooling of interests for financial accounting purposes. The consolidated financial statements give retroactive effect to the merger. Certain adjustments were made in those periods to conform the previous accounting policies of UTI with those of Patterson.

Jones Drilling Corporation — On January 5, 2001, the Company acquired assets consisting of 21 drilling rigs and related equipment and approximately $2.3 million of net working capital from Jones Drilling Corporation and three of its affiliated entities. The purchase price of $33.2 million consisted of 810,070 shares of the Company's common stock valued at $26.8125 per share and $11.3 million cash plus approximately $240,000 in transaction costs. The transaction was accounted for as a business combination and the purchase price, net of working capital acquired, was allocated among the assets acquired based on their estimated fair market values.

Other — In January 2001, the Company acquired six drilling rigs, through three separate transactions, for approximately $15.7 million cash in aggregate. The transactions were accounted for as acquisitions of assets and the purchase price was allocated among the assets acquired based on their estimated fair market values.

3. 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, 2003, 2002, and 2001 (in thousands):

	2003	2002	2001
Net income	$55,326	$2,169	$164,162
Other comprehensive income:			
Foreign currency translation adjustment related to our Canadian operations	8,773	457	(2,326)
Unrealized gain on equity securities, net of tax of $955 in 2003 and $18 in 2002	1,590	30	—
Comprehensive income	$65,689	$2,656	$161,836

4. Property and Equipment

Property and equipment consisted of the following at December 31, 2003 and 2002 (in thousands):

	2003	2002
Drilling rigs and related equipment	$1,022,795	$ 895,125
Other equipment	65,659	54,788
Oil and natural gas properties	57,625	52,011
Buildings	11,773	11,073
Land	3,684	3,779
	1,161,536	1,016,776
Less accumulated depreciation and depletion	(467,905)	(389,042)
	$ 693,631	$ 627,734

5. Goodwill and Other Intangible Assets

Intangible assets consist primarily of goodwill arising from business combinations. In accordance with SFAS No. 142, all of the Company's intangible assets that have definite lives are being amortized on a straight-line basis over their estimated useful lives and goodwill is evaluated to determine if fair value of the asset has decreased below its carrying value. At December 31, 2003, the Company evaluated its goodwill and other intangible assets and determined no adjustment to impair goodwill and other intangible assets was necessary. Amortization expense of approximately $4.7 million recognized during 2001, would not have been recognized under SFAS No. 142. Goodwill and other intangible assets as of December 31, 2003 and 2002 are as follows (in thousands):

	2003	2002
Goodwill	$ 69,860	$ 69,860
Accumulated amortization	(19,661)	(19,661)
Goodwill, net	50,199	50,199
Covenants-not-to-compete and other	$ 1,956	$ 1,956
Accumulated amortization	(976)	(842)
Other intangible assets, net	980	1,114
Intangible assets, net	$ 51,179	$ 51,313

The amount of goodwill and other intangible assets as of December 31, 2003 and 2002 assigned to the contract drilling and drilling and completion fluids operating segments, the only operating segments that had intangible assets for such periods, is as follows (in thousands):

2003			
Contract drilling:			
Goodwill	$56,543	Accumulated amortization	$16,278
Non-competes and other	$ 1,909	Accumulated amortization	$ 959
Drilling and completion fluids:			
Goodwill	$13,317	Accumulated amortization	$ 3,383
Non-competes and other	$ 47	Accumulated amortization	$ 17
2002			
Contract drilling:			
Goodwill	$56,543	Accumulated amortization	$16,278
Non-competes and other	$ 1,909	Accumulated amortization	$ 828
Drilling and completion fluids:			
Goodwill	$13,317	Accumulated amortization	$ 3,383
Non-competes and other	$ 47	Accumulated amortization	$ 14

Change in the net carrying amount of goodwill for the years ended December 31, 2003 and 2002 is as follows (in thousands):

	Drilling	Drilling & Completion Fluids	Total
Balance at December 31, 2001	$40,265	$9,934	$50,199
Changes to goodwill	—	—	—
Balance at December 31, 2002	40,265	9,934	50,199
Changes to goodwill	—	—	—
Balance at December 31, 2003	$40,265	$9,934	$50,199

Amortization expense consists of the following (in thousands):

	Years Ended December 31,		
	2003	2002	2001
Goodwill	$ —	$ —	$4,665
Covenants-not-to-compete and other	134	315	507
Total	$134	$315	$5,172

Our weighted average amortization period for other intangible assets is approximately 13 years. Estimated amortization expense for these assets is approximately $97,000 for each of the five succeeding fiscal years.

Had SFAS No. 142 been in effect prior to January 1, 2002, our reported net income and net income per share would have been as follows (in thousands, except per share amounts):

	Years Ended December 31,		
	2003	2002	2001
Net income:			
Reported	$55,326	$2,169	$164,162
Goodwill amortization	—	—	4,665
Adjusted	$55,326	$2,169	$168,827
Basic net income per common share:			
Reported	$ 0.68	$ 0.03	$ 2.15
Effect of goodwill amortization	—	—	0.06
Adjusted	$ 0.68	$ 0.03	$ 2.21
Diluted net income per common share:			
Reported	$ 0.67	$ 0.03	$ 2.07
Effect of goodwill amortization	—	—	0.06
Adjusted	$ 0.67	$ 0.03	$ 2.13

6. Investment in Equity Securities

In 2002, the Company purchased 1,058,673 shares of the common stock of TMBR, $.10 par value per share, for an aggregate cash purchase price of $17.6 million, or $16.60 per share, and approximately $84,000 of additional costs incurred to acquire the shares. At December 31, 2003, the Company owned approximately 19.2% of the outstanding shares of TMBR.

The accounting treatment of shares representing the Company's investment in the common stock of TMBR has been affected by the Company's ability to sell shares within one year. As of December 31, 2003, the Company no longer has restrictions on its ability to sell the TMBR shares within one year. Previously, the restricted shares were reflected in the balance sheet at cost under the cost method of accounting in accordance with Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investment in Common Stock". None of the TMBR shares are restricted from sale within one year. Accordingly, all shares are classified as Available-for-Sale and are reflected in the balance sheet at fair value in accordance with SFAS No. 115. Fair value is determined from publicly quoted market prices as of the balance sheet date. In accordance with SFAS No. 115, unrealized gains and losses recorded as a result of the adjustment to fair value are reflected directly in stockholders' equity.

The following table summarizes the Company's unrealized gain on its investment in equity securities as of December 31, 2003 and 2002 (in thousands, except share amounts):

	Common Shares	Cost	Unrealized Gain	Total
2003:				
TMBR/Sharp Drilling, Inc.				
Cost method	—	$ —	$ —	$ —
Available-for-Sale	1,058,673	17,681	2,593	20,274
	1,058,673	$17,681	$2,593	$20,274
2002:				
TMBR/Sharp Drilling, Inc.				
Cost method	892,742	$14,833	$ —	$14,833
Available-for-Sale	165,931	2,826	48	2,874
	1,058,673	$17,659	$ 48	$17,707

7. Accrued Expenses

Accrued expenses consisted of the following at December 31, 2003 and 2002 (in thousands):

	2003	2002
Salaries, wages, payroll taxes and benefits	$15,740	$10,573
Workers' compensation liability	22,859	15,516
Sales, use and other taxes	5,796	2,712
Insurance, other than workers' compensation	1,848	2,605
Restructuring and merger related costs	1,000	1,029
Other	4,823	3,078
	$52,066	$35,513

The following table summarizes activity in restructuring and merger related accrual accounts for the years ended December 31, 2003 and 2002, respectively (in thousands):

	2003	2002
Balance at beginning of year	$1,029	$2,200
Severance costs and related expenses	(21)	(324)
Closing of duplicate operational facilities	(4)	(392)
Professional fees	(4)	(455)
Balance at end of year	$1,000	$1,029

8. Asset Retirement Obligation

SFAS No. 143 requires that we record a liability for the estimated costs to be incurred in connection with the abandonment of oil and natural gas properties in the future. We recorded a liability of approximately

$1.1 million in the first quarter of 2003 upon initial adoption of SFAS No. 143. The following table describes the changes to our asset retirement obligations during 2003:

	2003
Balance at beginning of year	$1,056
Liabilities incurred	173
Liabilities settled	(100)
Accretion expense	34
Asset retirement obligation at end of year	$1,163

Had SFAS No. 143 been in effect as of January 1, 2001, the impact on the Company's results of operations would have been immaterial for the years ended December 31, 2002, and 2001 and the asset retirement obligation would have been $1.1 million, $1.0 million and $959,000 as of December 31, 2002 and 2001 and January 1, 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.

9. Notes Payable

There were no amounts outstanding under the Company's revolving credit facility at December 31, 2003 or December 31, 2002. The maximum borrowings under this revolving credit facility were increased from $90.0 million to $100.0 million in June 2001 and the term of the facility was also extended to June 2005. A fee of .375% per annum is assessed on the unused facility amount. The amount used for letters of credit decreases the borrowing base of the facility on a dollar-for-dollar basis. The revolving credit facility calls for periodic interest payments at a floating rate ranging from LIBOR plus 1.75% to 2.75%. The applicable rate above LIBOR (1.75% at December 31, 2003) is based upon our trailing twelve-month earnings before interest expense, income taxes and depreciation, depletion and amortization. Assets of the Company secure the facility. The facility has restrictions customary in financial instruments of this type including restrictions on certain investments, acquisitions and loans. The facility has no financial covenants unless availability under the facility is less than $20.0 million. The terms of the facility limit the payment of dividends without the prior written consent of the lenders.

During 2001, the Company repaid $89.2 million under its existing credit facilities and other term obligations. The Company incurred expenses of $448,000 as a result of prepayment penalties and $942,000 related to deferred financing costs which were unamortized at the time the debt was extinguished. The penalties and deferred financing costs were included in restructuring and other charges in 2001.

10. Commitments, Contingencies, and Other Matters

The Company maintains letters of credit in the aggregate amount of $37.0 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 coverages up to $50.0 million per occurrence and in the aggregate. We maintain a $1.0 million per occurrence deductible on our general liability insurance coverage and a $750,000 per occurrence deductible on our workers' compensation insurance coverage. These levels of self-insurance expose us 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's lender who has a security interest in the drilling rigs is named as loss payee on the physical damage insurance on such rigs.

Westfort Energy LTD and Westfort Energy (US) LTD f/k/a Canadian Delta, Inc. ("Westfort"), filed a lawsuit against two Patterson-UTI subsidiaries, Patterson Petroleum LP, and Patterson-UTI Drilling Company LP, in the Circuit Court, Rankin County, Mississippi, Case No. 2002-18. The lawsuit relates to a letter agreement entered into in July 2000 between Patterson Petroleum LP and Westfort concerning the drilling of a daywork well in Mississippi. This lawsuit was filed by Westfort after Patterson Petroleum LP made demand on Westfort for payment of the contract drilling services.

The Westfort lawsuit has been dismissed without prejudice. Westfort filed for bankruptcy in May of 2003. The Company continues to assert claims against Westfort including the monies owed Patterson Petroleum LP under the letter agreement in the amount of approximately $5,075,000. Amounts deemed uncollectible have been reserved. The Company believes that it is remote that the outcome of this matter will have a material adverse effect on the Company's financial condition and results of operations.

In this lawsuit, Westfort alleged breach of contract, fraud, and negligence causes of action. Westfort sought alleged monetary damages, the return of shares of Westfort stock, unspecified damages from alleged lost profits, lost use of income stream, and additional operating expenses, along with alleged punitive damages to be determined by the jury, but not less than 25% of the Company's net worth. The Company intends to vigorously contest these claims if reasserted by Westfort.

The Company is also 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.

11. Stockholders' Equity

During March 2002, the Company issued 650,000 shares of its common stock as consideration for the acquisition of Odin Drilling, Inc. (see Note 2). The common stock was valued at $26.06 per share, its fair market value on the date the terms of the transaction were agreed upon.

During December 2001, the Company issued 450,000 shares of its common stock and warrants to acquire an additional 325,000 shares at an exercise price of $26.75 per share, as partial consideration for the acquisition of 17 drilling rigs and related equipment from Cleere Drilling Company. The common stock was recorded at $21.55 per share and the warrants were valued at $8.00 per underlying share of common stock using the Black-Scholes option valuation model (see Note 2).

On May 8, 2001, pursuant to the merger between Patterson and UTI, the Company's stockholders approved an amendment to the Company's charter increasing the number of authorized shares of the Company's common stock to 200 million.

During January 2001, the Company issued 810,070 shares of its common stock as partial consideration for the acquisition of Jones Drilling Corporation and certain assets owned by its related entities (see Note 2). The common stock was valued at $26.8125 per share, its fair market value on the date of the transaction.

12. 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, 2003, 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 ("1997 Plan") (1) (3)	8,250,000	4,503,838	1,949,537
Amended and Restated Patterson-UTI Energy, Inc. 2001 Long-Term Incentive Plan ("2001 Plan") (2)	1,000,000	846,737	25,694
Amended and Restated Non-Employee Director Stock Option Plan of Patterson-UTI Energy, Inc. ("Non-Employee Director Plan") (1)	600,000	150,000	292,500
Patterson-UTI Energy, Inc. Non-Employee Directors' Stock Option Plan, as amended ("1995 Non-Employee Director Plan")	120,000	16,000	—
1997 Stock Option Plan of DSI Industries, Inc. ("DSI Plan") (1)	—	1,608	—
Amended and Restated Patterson-UTI Energy, Inc. 1996 Employee Stock Option Plan ("1996 Plan") (1)	—	238,900	—
Patterson-UTI Energy, Inc., 1993 Incentive Stock Plan, as amended ("1993 Plan")	2,800,000	368,675	—

(1) Plan was assumed by the Company as a part of the merger between Patterson and UTI.
(2) Plan is for the benefit of employees of the Company, other than officers and directors of the Company.
(3) Plan is for the benefit of employees of the Company, including 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.
- Although the plan allows for awards of tandem and independent stock appreciation rights, restricted stock and performance awards, no such awards have been granted.
- During 2003, the Company increased the options authorized for grant from 6,000,000 to 8,250,000.

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 20,000 shares upon becoming a director of the Company and options to purchase 10,000 shares on December 31 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.

Of the four dormant plans administered by the Company, two of the plans (the 1993 Plan and the 1995 Non-Employee Director Plan) were plans of the Company prior to the merger of Patterson and UTI and two of the plans (the DSI Plan and the 1996 Plan) were plans of UTI.

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 12,000 shares of the Company's common stock. These options vested on November 6, 2001 and terminate four years later on November 5, 2005. The exercise price of each of the options was $28.625, which was in excess of the fair market value of the Company's common stock on the date of grant.

A summary of the status of the Company's stock options issued as of December 31, 2003, 2002, and 2001 and the changes during each of the years then ended are presented below (in thousands, except weighted average exercise price):

	2003		2002		2001	
	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	6,139	$17.61	6,596	$10.40	5,488	$ 7.57
Granted	915	32.48	2,149	26.77	2,103	16.19
Exercised	(868)	11.84	(2,457)	6.41	(805)	5.26
Surrendered/Expired	(48)	19.97	(149)	15.32	(190)	14.39
Outstanding at end of year	6,138	$20.62	6,139	$17.61	6,596	$10.40
Exercisable at end of year	2,986	$16.29	2,395	$10.88	4,110	$ 7.52

The following table summarizes information about stock options outstanding at December 31, 2003:

	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
$3.125 to $5.00	832,681	5.17	$ 4.75	810,548	$ 4.74
$5.01 to $10.00	118,545	4.36	$ 9.35	118,545	$ 9.35
$10.01 to $15.00	201,958	3.65	$14.20	201,958	$14.20
$15.01 to $20.00	1,852,074	7.43	$16.02	812,097	$16.09
$20.01 to $25.00	47,500	3.88	$22.88	47,500	$22.88
$25.01 to $30.00	2,125,000	8.50	$26.72	949,912	$26.59
$30.01 to $32.93	960,000	8.76	$32.41	45,000	$31.07
	6,137,758	7.49	$20.62	2,985,560	$16.29

Pro Forma Stock-Based Compensation Disclosure — Pro forma information in accordance with SFAS No. 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 2003 respectively; dividend yield of 0.00%; risk-free interest rates are different for each grant and range from 2.81% 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 and 52.05% for all 2003 grants. The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts. SFAS No. 123 does not apply to awards prior to 1996.

Stock Purchase Warrants — In December 2001, the Company issued 325,000 warrants exercisable at $26.75 per share as partial consideration for the purchase of 17 drilling rigs and related equipment from Cleere Drilling Company (see Note 2). The warrants were fully exercisable at the date of issuance. If not exercised, the warrants will expire on December 21, 2004.

In June 2000, the Company issued 127,000 warrants exercisable at $22 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 and none remain outstanding at December 31, 2003.

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 certain transactions described in Notes 2 and 11:

	Shares	Weighted Average Exercise Price
Granted		
2003	915,000	$32.48
2002	2,148,500	26.77
2001	2,428,500	17.60
Exercised		
2003	970,782	$12.91
2002	2,481,486	6.56
2001	804,581	5.26
Surrendered		
2003	47,562	$19.97
2002	149,205	15.32
2001	190,473	14.39
Outstanding at Year End		
2003	6,462,758	$20.93
2002	6,566,101	18.13
2001	7,048,292	11.36
Exercisable at Year End		
2003	3,310,560	$17.32
2002	2,822,726	13.11
2001	4,562,259	9.29

13. Leases

The Company incurred rent expense, consisting primarily of daily rental charges for the use of drilling equipment, of $8.6 million, $5.7 million, and $5.9 million, for the years 2003, 2002, and 2001, respectively. The Company's obligations under non-cancelable operating lease agreements are not material to the Company's operations.

14. Income Taxes

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

	2003	2002	2001
Federal income tax expense (benefit):			
Current	$13,856	$(18,064)	$ 82,417
Deferred	14,509	21,687	10,887
	28,365	3,623	93,304
State income tax expense (benefit):			
Current	1,214	(1,811)	4,294
Deferred	76	1,117	661
	1,290	(694)	4,955
Foreign income tax expense (benefit):			
Current	18	(2,003)	1,062
Deferred	2,689	744	3,012
	2,707	(1,259)	4,074
Total:			
Current	15,088	(21,878)	87,773
Deferred	17,274	23,548	14,560
Total income tax expense	$32,362	$ 1,670	$102,333

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

	2003	2002	2001
Statutory tax rate	35.0%	35.0%	35.0%
State income taxes	1.5	2.8	1.9
Permanent differences	0.8	5.7	1.3
Other, net	(0.6)	—	0.2
Effective tax rate	36.7%	43.5%	38.4%

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, 2003 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.

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

	December 31, 2003	Net Change	December 31, 2002	Net Change	December 31, 2001	Net Change	January 1, 2001
Deferred tax assets:							
Net operating loss carryforwards	$ —	$ —	$ —	$ —	$ —	$ (5,850)	$ 5,850
Investment tax credit carryforwards	—	—	—	—	—	(469)	469
Workers' compensation allowance	10,107	2,934	7,173	2,663	4,510	3,951	559
AMT credit carryforwards	602	—	602	—	602	(3,770)	4,372
Other	5,740	(1,775)	7,515	3,880	3,635	(1,160)	4,795
Deferred tax assets	16,449	1,159	15,290	6,543	8,747	(7,298)	16,045
Deferred tax liabilities:							
Property and equipment basis difference	(143,490)	(16,484)	(127,006)	(34,147)	(92,859)	(16,005)	(76,854)
Net deferred tax liability	$(127,041)	$(15,325)	$(111,716)	$(27,604)	$(84,112)	$(23,303)	$(60,809)

The alternative minimum tax credit may be carried forward indefinitely.

15. Employee Benefits

The Company maintains a 401(k) plan for all eligible employees. The Company's operating results include expenses of $1.5 million in 2003, and $2.1 million in 2002 and 2001 for the Company's discretionary contributions to the plan.

16. 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. The Company owns 343 drilling rigs, of which 226 operated in 2003. Currently, 143 of the drilling rigs are based in West Texas and New Mexico, 56 in South Texas, 42 in the Ark-La-Tex region and Mississippi, 70 in the Mid-Continent region, 16 in the Rocky Mountain region, and 16 in Western Canada.

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 West Texas, Southeast New Mexico, South Texas, East Texas, Oklahoma, the Gulf Coast regions of Texas and 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, New Mexico, Oklahoma, and Colorado. Our 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.

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

	Years Ended December 31,		
	2003	2002	2001
Revenues:			
Contract drilling	$639,694	$410,295	$839,931
Pressure pumping	46,083	32,996	39,600
Drilling and completion fluids	69,230	69,943	94,456
Oil and natural gas	21,163	14,723	15,988
Total revenues	$776,170	$527,957	$989,975
Income before income taxes:			
Contract drilling	$ 75,666	$ 7,607	$274,514
Pressure pumping	10,442	6,090	12,649
Drilling and completion fluids	(1,960)	(278)	3,842
Oil and natural gas	7,784	3,945	756
Corporate and other	(7,194)	(9,266)	(11,444)
Merger costs	—	—	(5,943)
Restructuring and other charges(a)	2,452	(4,700)	(7,202)
Interest income	1,116	1,110	2,080
Interest expense	(292)	(532)	(3,142)
Other	143	(137)	385
Income before income taxes	$ 88,157	$ 3,839	$266,495

(a) Restructuring and other charges relate 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.

	Years Ended December 31,		
	2003	2002	2001
Identifiable assets:			
Contract drilling	$ 801,109	$694,020	$681,700
Pressure pumping	46,763	35,084	29,473
Drilling and completion fluids	30,860	34,687	41,724
Oil and natural gas	33,494	20,854	15,398
Corporate and other (a)	163,604	157,864	101,347
Total assets	$1,075,830	$942,509	$869,642
Depreciation, depletion and amortization:			
Contract drilling	$ 84,379	$ 80,500	$ 72,797
Pressure pumping	3,774	2,803	1,895
Drilling and completion fluids	2,319	2,216	2,644
Oil and natural gas	7,082	5,251	8,505
Corporate and other	444	446	318
Total depreciation, depletion and amortization	$ 97,998	$ 91,216	$ 86,159
Capital expenditures:			
Contract drilling	$ 95,175	$ 68,516	$150,788
Pressure pumping	10,524	7,399	7,756
Drilling and completion fluids	912	1,571	4,937
Oil and natural gas	10,484	6,357	7,956
Corporate and other	—	—	5,320
Total capital expenditures	$ 117,095	$ 83,843	$176,757

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

17. Quarterly Financial Information

Quarterly financial information for the years ended December 31, 2003 and 2002 is as follows (in thousands):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Total
2003					
Operating revenues	$165,239	$195,624	$207,015	$208,292	$776,170
Operating income	9,844	19,153	27,354	30,839	87,190
Net income	5,756	12,052	17,113	20,405	55,326
Earnings per share:					
Basic	$ 0.07	$ 0.15	$ 0.21	$ 0.25	$ 0.68
Diluted	$ 0.07	$ 0.15	$ 0.21	$ 0.25	$ 0.67
2002					
Operating revenues	$128,223	$125,363	$133,495	$140,876	$527,957
Operating income (loss)	6,428	(6,591)	683	2,878	3,398
Net income (loss)	3,935	(3,845)	249	1,830	2,169
Earnings (loss) per share:					
Basic	$ 0.05	$ (0.05)	$ 0.00	$ 0.02	$ 0.03
Diluted	$ 0.05	$ (0.05)	$ 0.00	$ 0.02	$ 0.03

18. 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, 2003 and 2002, the Company's demand deposits and temporary cash investments consisted of the following (in thousands):

	2003	2002
Deposits in FDIC and SIPC-insured institutions under $100,000	$ (3,326)	$ 1,711
Deposits in FDIC and SIPC-insured institutions over $100,000	112,226	90,464
	108,900	92,175
Less outstanding checks and other reconciling items	(8,417)	(10,021)
Cash and cash equivalents	$100,483	$ 82,154

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, 2003, 2002, or 2001. We recognized bad debt expense for 2003, 2002, and 2001 of $259,000, $320,000, and $2.0 million, 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.

19. Related Party Transactions

Use of Assets — In 2001, we leased a 1981 Beech King-Air 90 airplane owned by SSI Oil and Gas, Inc., an entity beneficially owned 50% by Cloyce A. Talbott, Patterson-UTI's Chief Executive Officer, and directly owned 50% by A. Glenn Patterson, Patterson-UTI's President/Chief Operating Officer. Under the terms of the lease, we paid a monthly rental of $9,200, the costs of fuel, insurance, taxes and maintenance of the aircraft. Such amounts totaled approximately $212,000 for the year ended December 31, 2001.

Joint Operation of Oil and Natural Gas Properties — The Company operates 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 originated or acquired by Patterson-UTI. At December 31, 2003, affiliated persons were working interest owners in 236 of the 260 wells operated by Patterson-UTI. Sales of working interests are made by Patterson-UTI to reduce its economic risk in the properties. 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 $11.1 million, $6.9 million, and $8.3 million from these properties in 2003, 2002, and 2001, respectively. These persons or entities were in turn billed for joint operating costs (including drilling and other development expenses) of $7.9 million, $5.5 million, and $5.9 million incurred in 2003, 2002, and 2001, respectively. This activity resulted in a net receivable from the affiliated persons of approximately $17,000 at December 31, 2003 and a net payable to the affiliated persons of approximately $466,000 at December 31, 2002.

Other — In 2003, 2002 and 2001, we paid approximately $740,000, $279,000 and $387,000, 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 2003, we paid approximately $209,000 to Melco Services ("Melco") for dirt contracting services and $59,000 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.

20. 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 by the Company for the years ended December 31, 2003, 2002 and 2001 are summarized below (in thousands):

	2003	2002	2001
Property acquisition costs	$ 1,120	$ 905	$ 3,813
Exploration costs	7,572	6,267	6,788
Development costs	1,531	845	1,354
	$10,223	$8,017	$11,955

The aggregate amount of capitalized costs of oil and natural gas properties as of December 31, 2003, 2002 and 2001 is comprised of the following (in thousands):

	2003	2002	2001
Proved properties	$ 50,481	$ 44,849	$ 43,500
Accumulated depreciation and depletion	(42,405)	(35,684)	(35,828)
	$ 8,076	$ 9,165	$ 7,672

Results of operations for oil and natural gas producing activities:

	2003	2002	2001
Oil and natural gas sales	$19,058	$12,738	$13,842
Gain on sale of oil and natural gas properties	571	303	213
	19,629	13,041	14,055
Costs and expenses:			
Lease operating and production costs	3,479	3,068	3,393
Exploration costs including dry holes and abandonments	1,073	785	1,212
Depreciation and depletion	5,638	4,633	7,417
Impairment of oil and natural gas properties	1,444	727	1,088
	11,634	9,213	13,110
Results of operations for oil and natural gas producing activities, before taxes	$ 7,995	$ 3,828	$ 945

Oil and natural gas reserve quantities:

The following table sets forth information with respect to quantities of net proved developed oil and natural gas reserves and changes in those reserves for the years ended December 31, 2003, 2002, and 2001 (in thousands). The quantities were estimated by an independent petroleum engineer. The Company's proved developed oil and natural gas reserves are located entirely within the United States.

	Oil (Bbls)	Gas (Mcf)
Estimated quantity, January 1, 2001	1,129	3,880
Revision in previous estimates	16	609
Extensions, discoveries and other additions	175	1,862
Sales of reserves	(1)	—
Production	(272)	(1,717)
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

Estimates of our 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 estimates. These assumptions are held constant throughout the life of the properties, except operating costs are adjusted for contractual escalations. Our reserve 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 our reserves as of December 31, 2003 were $32.52 per Bbl of oil and $6.19 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,		
	2003	2002	2001
Future gross revenues	$ 70,894	$ 68,165	$ 32,674
Future development and production costs	(23,021)	(22,149)	(13,077)
Future income tax expense(a)	(15,155)	(15,964)	(5,110)
Future net cash flows	32,718	30,052	14,487
Discount at 10% per annum	(8,768)	(8,952)	(3,773)
Standardized measure of discounted future net cash flows	$ 23,950	$ 21,100	$ 10,714

(a) Future income taxes are computed by applying the statutory tax rate to future net cash flows less the tax basis of the properties and net operating loss attributable to oil and natural gas operations and investment tax credit carryforwards as of year-end; statutory depletion and tax credits applicable to future oil and natural gas-producing activities are also considered in the income tax computation.

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,		
	2003	2002	2001
Standardized measure at beginning of year	$21,100	$10,714	$16,640
Sales and transfers of oil and natural gas produced, net of production costs	(11,362)	(8,342)	(8,684)
Net changes in sales price and future production and development costs	4,718	4,888	(10,670)
Extensions, discoveries and improved recovery, less related costs	10,052	6,017	2,870
Sales of minerals-in-place	(2,017)	(30)	(1)
Revision of previous quantity estimates	(2,976)	4,315	(2,824)
Accretion of discount	3,547	1,531	2,440
Other	101	(9,358)	13,588
Net change in income taxes	787	11,365	(2,645)
Standardized measure at end of year	$23,950	$21,100	$10,714

PATTERSON-UTI ENERGY, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance	Additions(1) Charged to Costs and Expenses	Additions(1) Acquired through Acquisition	Deductions(2)	Ending Balance
			(In thousands)		
Year Ended December 31, 2003					
Deducted from asset accounts:					
Allowance for doubtful accounts	$3,144	$ 259	$—	$1,270	$2,133
Year Ended December 31, 2002					
Deducted from asset accounts:					
Allowance for doubtful accounts	$4,021	$ 320	$—	$1,197	$3,144
Year Ended December 31, 2001					
Deducted from asset accounts:					
Allowance for doubtful accounts	$3,462	$2,045	$—	$1,486	$4,021

(1) Net of recoveries.

(2) Uncollectible accounts written off.

SIGNATURES

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

PATTERSON-UTI ENERGY, INC.

By: /s/ CLOYCE A. TALBOTT

Cloyce A. Talbott
Chief Executive Officer

Date: February 4, 2004

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of Patterson-UTI Energy, Inc. and in the capacities indicated as of February 4, 2004.

Signature	Title
/s/ MARK S. SIEGEL Mark S. Siegel	Chairman of the Board
/s/ CLOYCE A. TALBOTT Cloyce A. Talbott *(Principal Executive Officer)*	Chief Executive Officer and Director
/s/ A. GLENN PATTERSON A. Glenn Patterson	President, Chief Operating Officer and Director
/s/ KENNETH N. BERNS Kenneth N. Berns	Senior Vice President and Director
/s/ JONATHAN D. NELSON Jonathan D. Nelson *(Principal Accounting Officer)*	Vice President, Chief Financial Officer, Secretary and Treasurer
/s/ ROBERT C. GIST Robert C. Gist	Director
/s/ CURTIS W. HUFF Curtis W. Huff	Director
/s/ TERRY H. HUNT Terry H. Hunt	Director
/s/ KENNETH R. PEAK Kenneth R. Peak	Director
/s/ NADINE C. SMITH Nadine C. Smith	Director

CERTIFICATIONS

I, Cloyce A. Talbott, certify that,

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

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

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

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

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

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

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

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

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

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

/s/ CLOYCE A. TALBOTT

Cloyce A. Talbott
Chief Executive Officer

Date: February 4, 2004

CERTIFICATIONS

I, Jonathan D. Nelson, certify that:

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

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

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

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

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

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

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

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

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

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

/s/ JONATHAN D. NELSON

Jonathan D. Nelson
Vice President, Chief Financial Officer, Secretary and Treasurer

Date: February 4, 2004

Corporate Information

CORPORATE OFFICE

Patterson-UTI Energy, Inc.
P.O. Box 1416
Snyder, Texas 79550

4510 Lamesa Highway
Snyder, Texas 79549

Telephone: (325) 574-6300
Fax: (325) 574-6390
www.patenergy.com

COMMON STOCK

Nasdaq: PTEN

TRANSFER AGENT

Continental Stock
Transfer & Trust Company
17 Battery Place
New York, NY 10004
Toll-Free number:
(800) 509-5586
www.continentalstock.com

INDEPENDENT AUDITOR

PricewaterhouseCoopers LLP

CORPORATE COUNSEL

Fulbright & Jaworski LLP

DIRECTORS

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

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

Glenn Patterson
President and Chief Operating Officer, Patterson-UTI Energy, Inc.

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

Robert C. Gist
Attorney at Law

Curtis W. Huff
President and Chief Executive Officer, Freebird Investments LLC

Terry H. Hunt
Energy Consultant and Investor

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

Nadine C. Smith
Business Consultant and Investor

CORPORATE OFFICERS

Mark S. Siegel
Chairman

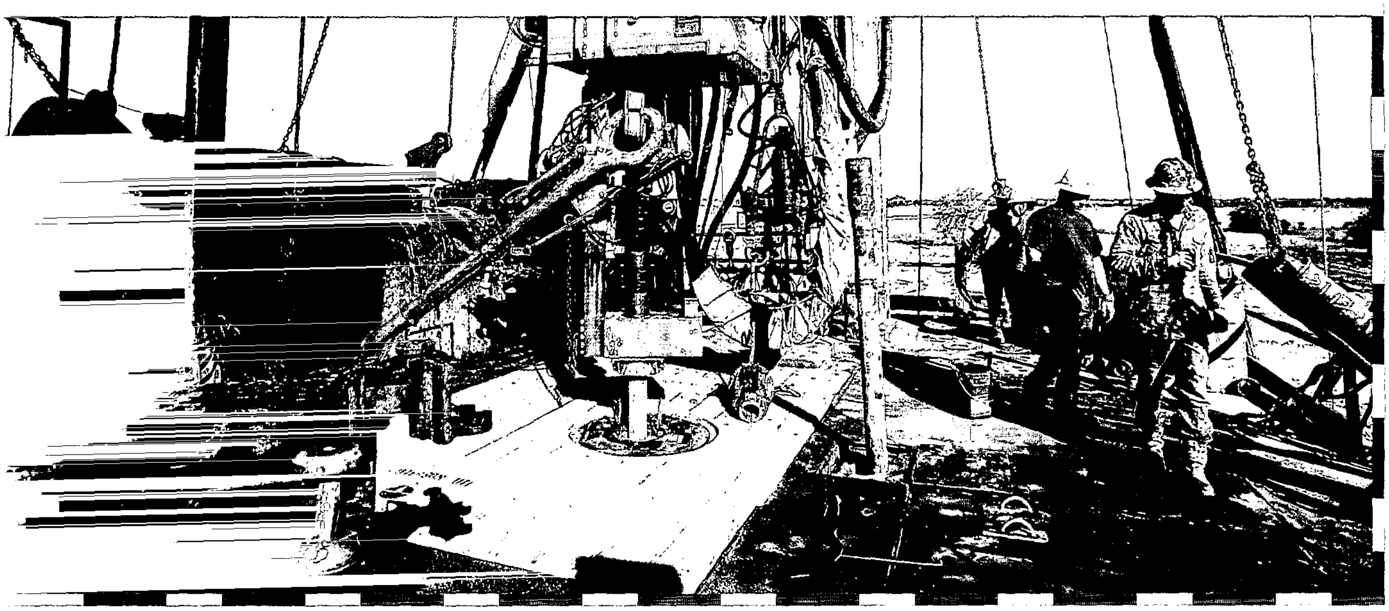
Cloyce A. Talbott
Chief Executive Officer

Glenn Patterson
President and Chief Operating Officer

Kenneth N. Berns
Senior Vice President

Jonathan D. (Jody) Nelson
Vice President, Chief Financial Officer, Secretary and Treasurer

John E. Vollmer III
Senior Vice President-Corporate Development



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