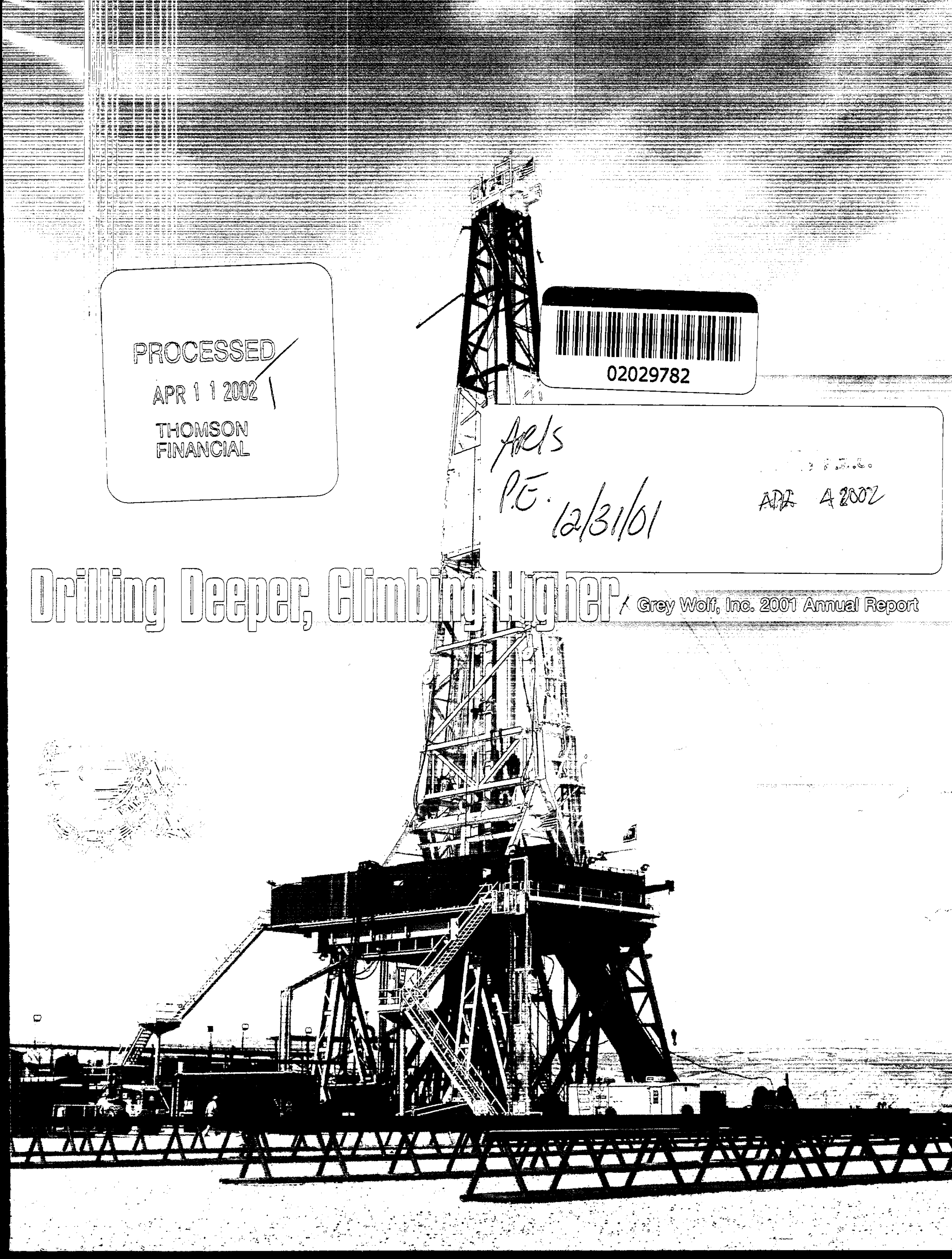
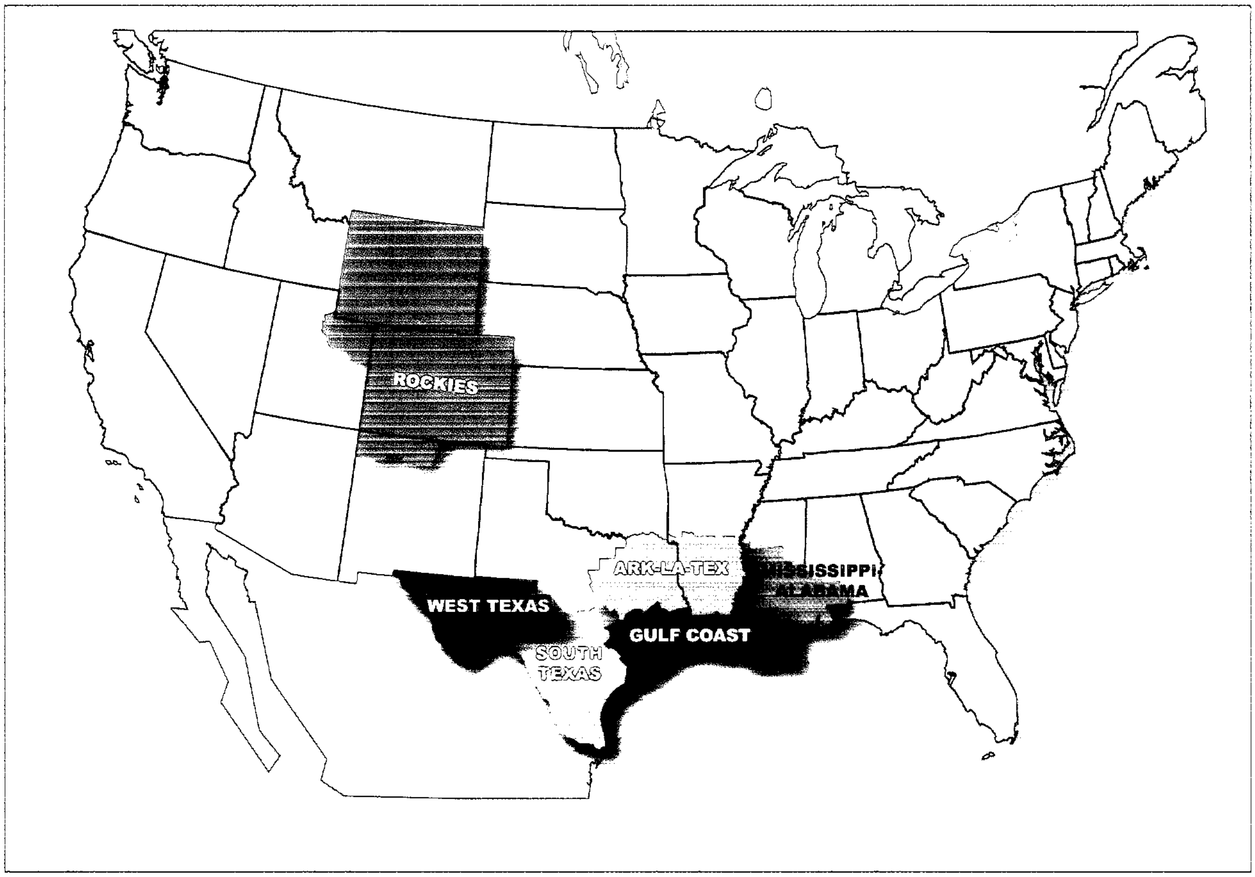


Drilling Deeper, Climbing Higher

/ Grey Wolf, Inc. 2001 Annual Report

Grey Wolf, Inc. is a leading provider of contract oil and gas land drilling services in the United States serving major and independent oil and gas companies with its premium fleet of 120 drilling rigs. The Company operates in the South Texas, West Texas, Gulf Coast, Ark-La-Tex, Mississippi/Alabama and Rocky Mountain markets – areas with the nation's most significant onshore natural gas reserves. With superior equipment and quality crews, Grey Wolf continues to provide value-added services to customers facing the technical challenges of deeper and more complex drilling projects.



On the Cover:

Based in the Rockies, Grey Wolf's Rig 558 – one of the world's largest land rigs – is ideally suited to drill challenging formations to depths exceeding 24,000 feet.

Financial Highlights

(in thousands, except per share amounts)

	1997	1998	1999	2000	2001
Revenues	$ 215,923	$ 240,979	$ 147,203	$ 269,334	$ 421,501
Net income (loss)	9,978	(83,213)	(41,262)	(8,523)	68,453
Earnings (loss) per share:					
Basic	0.07	(0.50)	(0.25)	(0.05)	0.38
Diluted	0.07	(0.50)	(0.25)	(0.05)	0.38
Total Assets	533,752	501,303	452,846	510,866	623,876
Long-term debt	176,530	250,832	249,962	249,851	250,695
Shareholders' equity	249,216	166,691	125,577	173,416	245,297
Working capital	66,644	44,489	16,353	60,029	113,163

Operational Highlights

	1997	1998	1999	2000	2001
Operating days	24,405	26,230	16,436	26,107	30,924
Average revenue per rig day	$ 8,847	$ 9,187	$ 8,956	$ 10,317	$ 13,630
Average margin per rig day	$ 2,187	$ 1,824	$ 382	$ 2,150	$ 5,963
Average rigs operating	67	72	45	71	85

To Our Shareholders

2001 was the best year in Grey Wolf's history. With well-executed business strategies and early momentum from high levels of drilling activity, we delivered on the goals we set a year ago. Specifically, we:

- improved the balance sheet,
- increased liquidity,
- achieved superior operating margins,
- upgraded rigs while exercising capital spending discipline, and
- used term contracts to mitigate the cyclical nature of dayrates.

Grey Wolf reported net income of $68.5 million, or $0.38 per share on a diluted basis, for the year ended December 31, 2001. This compares with a loss in 2000 of $8.5 million, or $0.05 per share on a diluted basis. Revenues rose 57% to $421.5 million for 2001, while the Company's operating margin per rig day averaged $5,963 – a 177% increase from the year 2000. Earnings before interest, taxes, depreciation and amortization (EBITDA) were up 264% to $174.5 million versus $47.9 million a year earlier.

By practicing strict financial discipline as we deployed rigs in this last market upturn, we enhanced our operating margins and made significant improvements in our balance sheet. Our net debt to total capitalization improved from 65.0% in early 2000 to 30.6% at December 31, 2001. Our liquidity has never been stronger, putting us in solid position to withstand the downturn in the drilling market that began midway through the year. At December 31, 2001, we had $99.1 million in cash versus $51.6 million a year earlier. We also had $75 million available under our recently amended line of credit that extends to the year 2006.

We were disappointed that the up-cycle in drilling activity was so short, lasting from May 1999 through mid 2001. This downturn is the first in my recollection caused by reduced energy demand rather than over supply. The recession pushed industries to cut natural gas use, then prices fell and drilling activity followed. Grey Wolf's average-rigs-working declined from 92 in the second quarter to 68 in the fourth quarter.

Fortunately, Grey Wolf locked in a revenue stream by signing term contracts as it deployed rigs during the upturn. The Company has 21 rigs working under term contracts with 6,000 rig days contracted in 2002 and 1,350 days in 2003. We adhered to a policy of contracting rigs from inventory under terms that cover the incremental cost of deployment and provide a reasonable return on the capital expended over the contract life of one to two years.

The average daily operating margin on our term contracts is approximately $7,000, reflecting higher dayrates that prevailed when the contracts were signed. At this writing, leading edge daywork bid rates have declined to between $7,500 and $8,500 without fuel or top drives versus a spread of $13,500 to $17,000 at the recent peak. Term contracts significantly support operating margins and liquidity in this downturn.

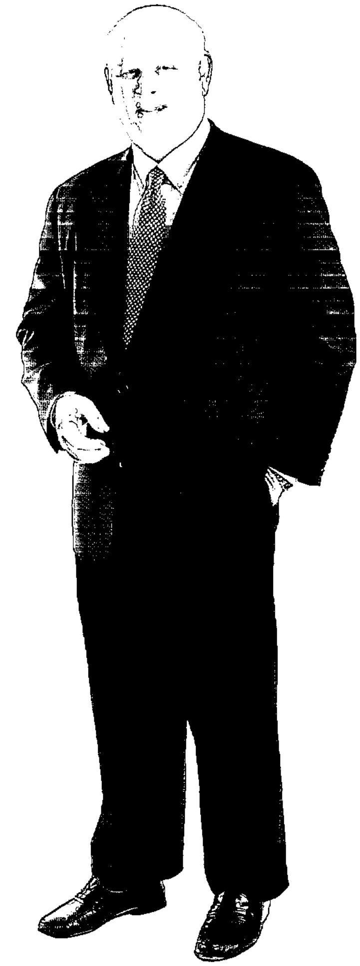
Consistent with our strategy of operating the best equipment in the best natural gas markets, Grey Wolf entered the Rocky Mountain and West Texas markets through term contracts in 2001. We have six rigs working in those regions today and will be seeking additional opportunities through new offices in Casper, Wyoming and Midland, Texas.

Grey Wolf is able to negotiate term contracts in large part because customers view the company as a premium drilling contractor with superior equipment and quality personnel. We continue to invest in the equipment needed to meet the technical challenges of the most demanding land drilling programs. Capital expenditures for 2001 totaled $106.6 million, including $55.5 million for rig upgrades and reactivation, $20.0 million for drill pipe and collars, and $7.2 million for the purchase of top drives.

More importantly, we continue to invest in our people. In the last downturn, Grey Wolf retained its experienced drillers and toolpushers. We refrained from cutting wages. When many contractors scrambled to fill jobs as the average weekly land rig count nearly tripled, Grey Wolf responded quickly with highly qualified, competent crews. Today, some contractors are again cutting wages. We do not intend to do so.

The long-term outlook for land drilling continues to be very positive. In the near-term, however, exploration and production companies will increase drilling programs only when gas prices improve. The next upturn should see a fairly quick move to higher rig utilization levels and dayrates because our customers are financially positioned today to resume drilling programs rapidly in response to any inflection in commodity prices.

Grey Wolf entered the latest downturn in excellent position to maintain liquidity and to enhance its long-term position in this industry. In the past decade, dayrates and rig utilization have been higher at the peak and higher at the trough with each succeeding cycle. We strive to enter each phase of these cycles in better position than the last, and we are succeeding in that effort.



Success is a team effort. 2001 was a great year. I appreciate the dedication of our employees and the support of our shareholders in achieving our goals.

Sincerely,

Thomas P. Richards
Chairman, President and
Chief Executive Officer

March 12, 2002

"A cornerstone of Grey Wolf's strategy is the belief that we must maintain superior equipment in the nation's most prolific gas markets. Recent rig upgrades capitalize on our fleet's deep-drilling bias, boost drilling efficiency and safety, and standardize equipment rig-to-rig." – Ed Jacob, Senior Vice President, Operations and Marketing

Surpassing all previous records, Grey Wolf climbed higher and drilled deeper in 2001 than ever before. It solidified its position as a leading land drilling contractor in the nation's most prolific natural gas markets by:

- significantly upgrading rigs under term contracts,
- signing long-term contracts that will keep rigs working in the current downturn,
- entering the Rocky Mountain and West Texas markets, and
- adhering to a policy of keeping experienced rig personnel through the market cycle.

A Superior Fleet Produces Solid Margins

Grey Wolf reported the highest margins in its history in 2001, reflecting the advantage of superior drilling equipment. More than 96% of the wells the Company drills are targeted to natural gas and natural gas drilling accounts for 80% of North American drilling activity. As the search for natural gas becomes more complex, exploration and production companies are willing to pay a premium for equipment that can efficiently target the deep geologic formations producing the greatest volumes of gas.

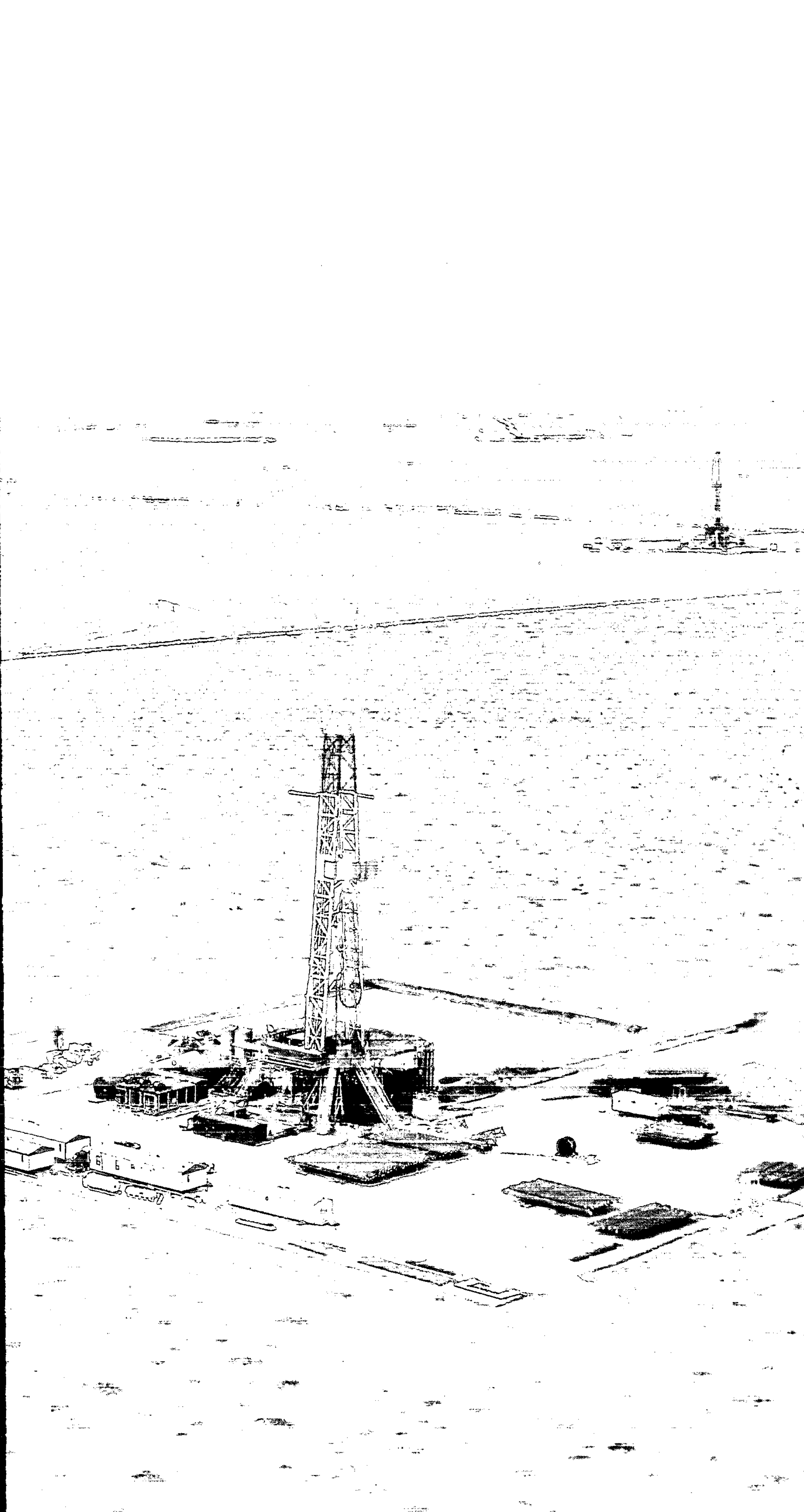
Of Grey Wolf's 120 land drilling rigs, more than 95%, including 62 diesel electric and 17 trailer-mounted rigs, can drill deeper than 10,000 feet. The fleet logged an average measured well depth of 11,470 feet in 2001—the second deepest in U.S. land drilling. This deep-drilling bias places Grey Wolf squarely at the quality end of the market where margins are the strongest.

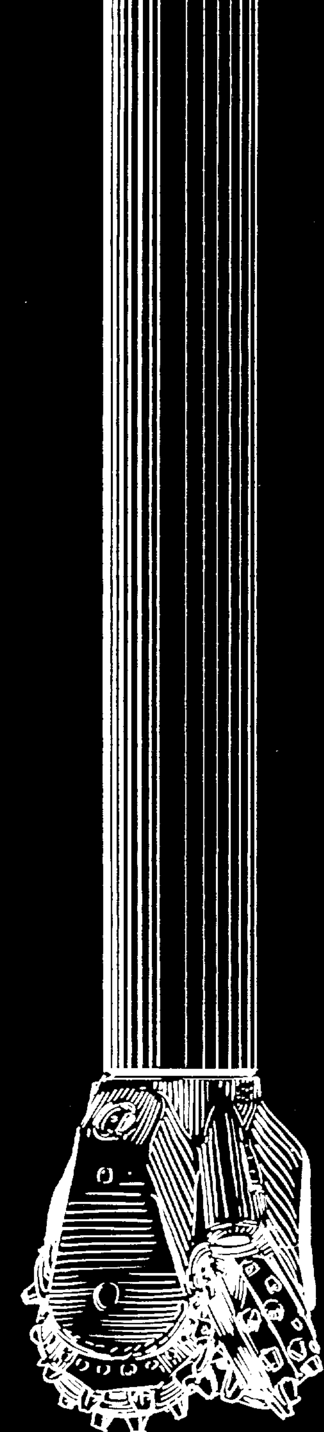
Ten rigs were significantly upgraded in 2001 as they were put to work under term contracts that will cover the $55.5 million cost of refurbishment. Customers are looking for rigs capable of using higher tensile-strength drill pipe, improved hydraulics, higher rotary speeds and better solids control equipment to handle the technical challenges of horizontal and multi-directional well drilling.

While broadening the overall capabilities of rig designs with new components, such as brake cooling systems that extend equipment life, the upgrades also improve safety, reduce costs, standardize equipment from rig-to-rig, and extend Grey Wolf's deep-drilling capabilities.

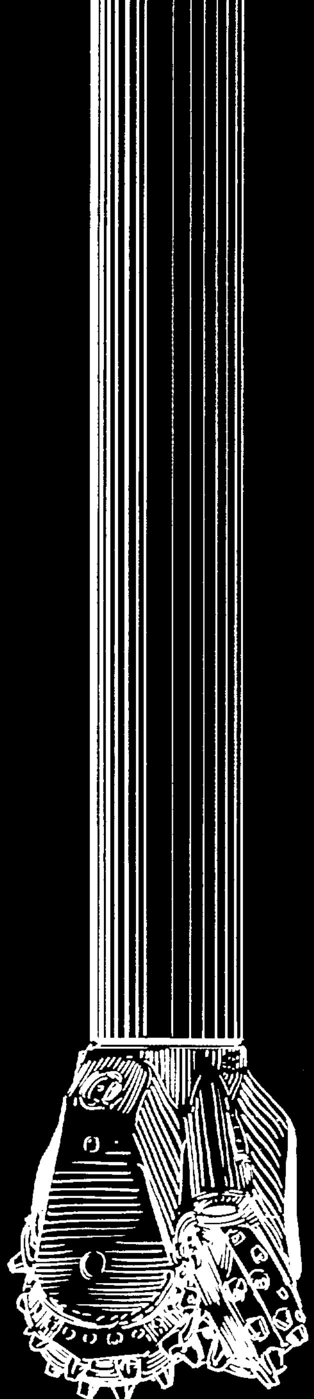
The upgrade of Grey Wolf's ultra-deep, state of-the-art drilling Rig 558 reflects Grey Wolf's revitalization goals. The 4,000 horsepower unit began drilling a 24,700-foot well in Wyoming's Madden Deep Unit in the Wind River Basin under an $11.6 million, two-year term contract with Burlington Resources. The challenge of drilling through formations with extreme pressures and high concentrations of hydrogen sulfide and carbon dioxide requires technically superior equipment.

Grey Wolf recommended using new high-tensile 5 ⅞" drillstring – its first use in U.S. land drilling – to





Rig 81 is one of four Grey Wolf entries into the West Texas market, reflecting the region's requirement for premium equipment and experienced crews. Establishing operations in the West Texas and Rocky Mountain markets extends Grey Wolf's presence in the best gas-producing regions.



Crews familiar with their rigs and the particular drilling challenges of their operating regions are a valued asset at Grey Wolf, which retains experienced drillers and toolpushers and refrains from cutting wages during cyclical downturns. In addition to diverse training programs in safety and operating procedures, this policy increases productivity and adds value for our customers.

"Grey Wolf's balance sheet is the strongest in its history. With $99 million in cash at year end and a $75 million line of credit available, Grey Wolf is well positioned to take advantage of opportunities." — David Wehlmann, Senior Vice President and Chief Financial Officer

reduce the time required to drill to the target depth. Also enhancing the rig's capabilities are a new high-pressure blow-out preventer, three 1,700 horsepower mud pumps, and a 750-ton top drive that allows the operator to rotate the drillstring going in or coming out of the hole. The top drive also reduces the number of drillstring connections from every 30 feet to every 90 feet. On a 24,000-foot well, this saves a significant amount of time.

In the past three years, the Company invested $16.1 million in 13 top drives for its fleet. Because of the increases in efficiency and safety on rigs equipped with top drives, these units command rates of $1,500 a day, further enhancing operating margins. Grey Wolf also invested $2.9 million in its trucking fleet, which operates in the South Texas and Ark-La-Tex markets to speed rig transits and to capture additional margin.

With a premium rig fleet, Grey Wolf should continue to produce margins exceeding those of competitors when the current market dynamics improve. Industry consolidation and attrition reduced the size of the U.S. rig fleet since the last building cycle in the late 1970s through early 1980s. Analysts suggest that rig utilization at levels not much higher than those seen in early 2001 will lead to a shortage of equipment, especially within the ranks of technically superior rigs that command the highest dayrates.

Term Contracts Accomplish Strategic Goals

Grey Wolf's balance sheet is stronger than at any time in its history. During the upturn in land drilling in 2000 and early 2001, Grey Wolf exercised fiscal caution as it brought rigs out of inventory to "marketed" status. As part of that strategy, the Company shifted to its customers some of the risk of investing capital to deploy cold-stacked rigs. It has 21 term contracts that cover the costs of upgrading the rigs while also providing an acceptable rate of return on capital employed over the one to two-year terms.

Recession became more evident as 2001 progressed and gas prices pulled back from record highs that hit $10.50 per thousand cubic feet December 31, 2000. This past December, natural gas was $2.77 per Mcf—back to levels that still exceed historic averages of the past decade. Nevertheless, rig utilization fell steeply from mid-year through year-end. Grey Wolf's average number of rigs working declined from a peak of 95 in the second quarter to 60 at year-end.

Despite the downturn, Grey Wolf entered 2002 with 60 rigs working, 21 of them under long term contracts that give the Company a solid operating base. Approximately 6,000 days are contracted for 2002, and 1,350 days are contracted in 2003 with average daily margins approximating $7,000 per day.

"Retaining experienced drillers and toolpushers, despite market cycles, gives Grey Wolf an advantage in terms of safety, knowledge, efficiency and customer rapport that's unsurpassed in this industry. Doing the right thing for our employees accrues to the bottom line." — Gary Lee, Senior Vice President, Human Resources

One of Grey Wolf's goals is to enter and exit each phase of the drilling cycle in a stronger position than the last. A premium rig fleet and outstanding personnel have made it possible to boost margins during upturns and mitigate a portion of the financial risk of a down market through term contracts as well as through turnkey services.

Relying upon highly experienced engineering and operations personnel, Grey Wolf is the leading land drilling contractor providing turnkey services to oil and gas companies in its core markets. Turnkey work represented 7% of activity in 2001 with an operating margin of $7,950 per day compared to $5,814 for daywork. The Company provides all the services associated with drilling a well to a specified depth and bears the drilling-related risks and costs. Margins are therefore higher than on daywork, but are dependent on accurate bidding and efficient on-site work – a testament to the Company's expertise in its core markets.

Rocky Mountains and West Texas Offer New Opportunities

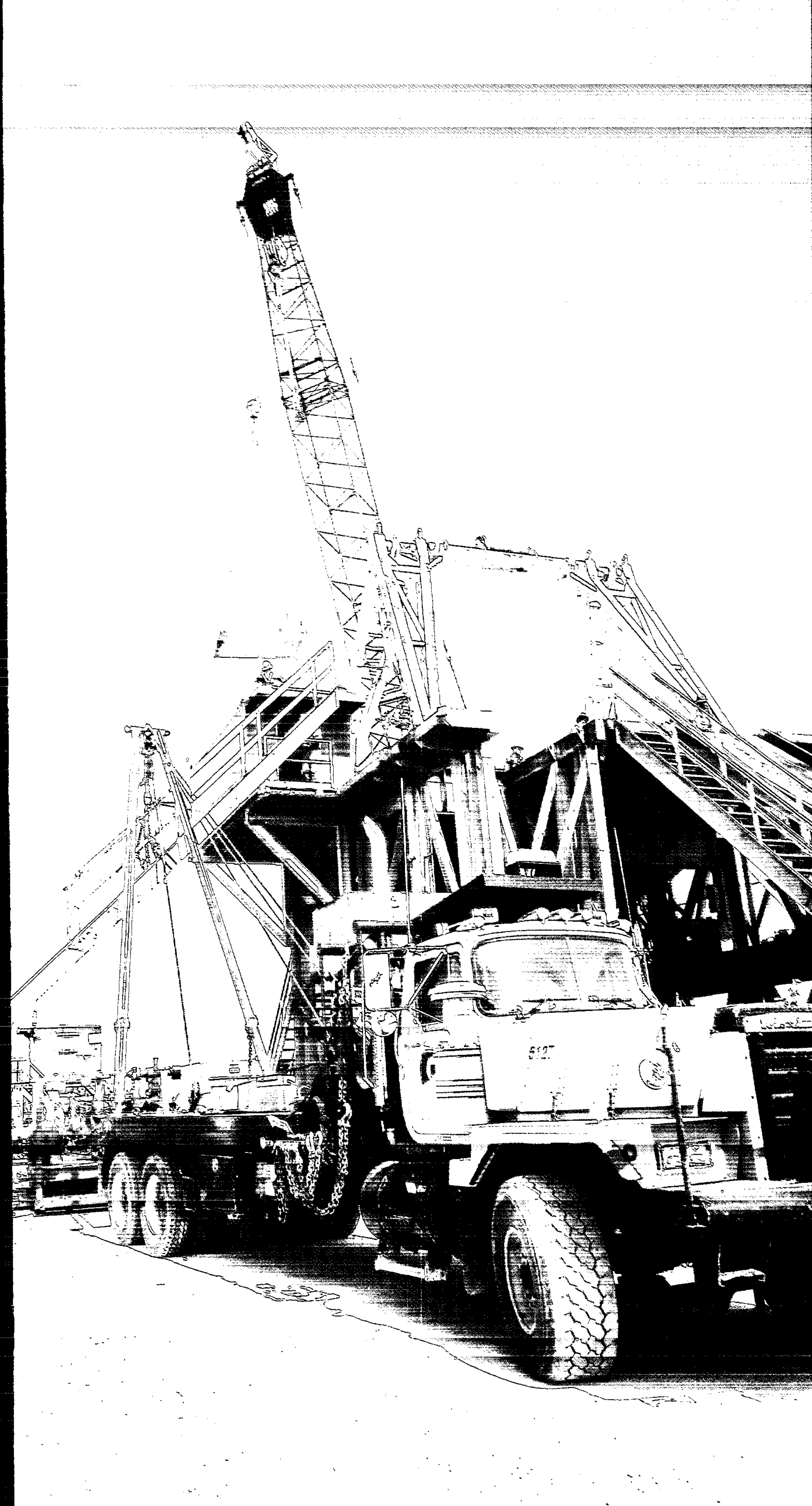
Deep gas prospects are providing growing opportunities for Grey Wolf's premium drilling fleet in West Texas and the Rocky Mountains. To meet anticipated increases in long-term demand for natural gas, operating companies are targeting gas in geologic formations that only a few years ago were considered economically or technically unfeasible to drill.

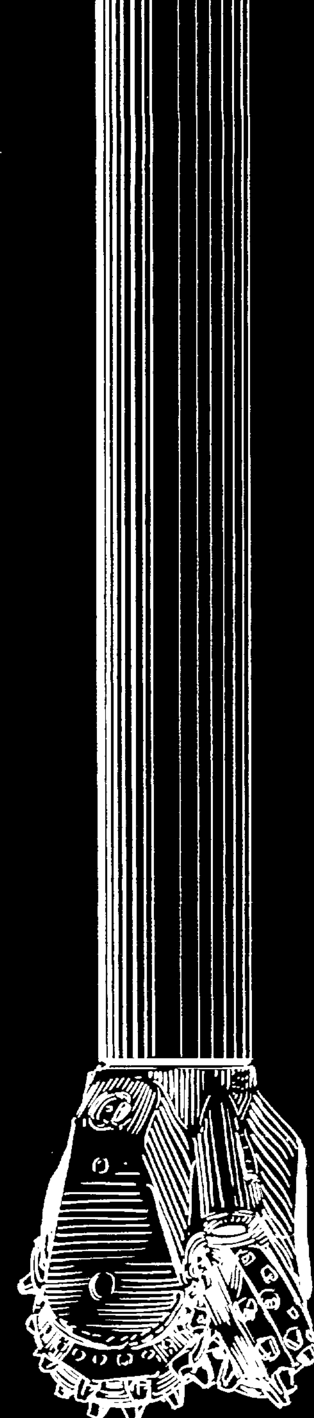
Grey Wolf's Rig 558, one of the world's largest land rigs with a 1,250-ton lift capacity, led the Company into the Rocky Mountain gas market, a region that today produces 15 percent of total U.S. supply. Rig 92, a 3,000 horsepower diesel electric SCR rig, began drilling under a one-year contract with ExxonMobil in southwest Wyoming in the fourth quarter 2001. An office established in Casper, Wyoming will direct these operations and further market expansion.

Grey Wolf moved four rigs to the West Texas region that are working today. The newly upgraded Rig 88 will begin work under a two-year contract with Tom Brown, Inc. later this year. Grey Wolf established a Midland office to pursue opportunities in this market.

Entry into these new markets is in line with Grey Wolf's strategy to serve as a "pure gas play" in the nation's most prolific gas producing regions. The Company's Gulf Coast, Ark-La-Tex and South Texas divisions are consistent market leaders in these historically high gas producing regions.

Our nation's gas supply and demand remain in fairly close balance despite recessionary factors in 2001 that reduced industrial use. To some extent, low gas prices are self-correcting as industrial and power





Efficient and cost effective rig moves are accomplished with a fleet of 61 trucks in the South Texas and Ark-La-Tex divisions, while further productivity gains are ensured with Grey Wolf's investment in 13 top drives. Commanding rates of $1,500 per day, top drives reduce the number of drill string connections and boost productivity.

"The name Wind River Basin has a very easy and smooth sound to it, but this area poses difficulties as we cut through challenging formations to depths easily exceeding 20,000 feet. The Rockies are ideally suited to our technical capabilities." — Ed Jacob, Senior Vice President, Operations and Marketing

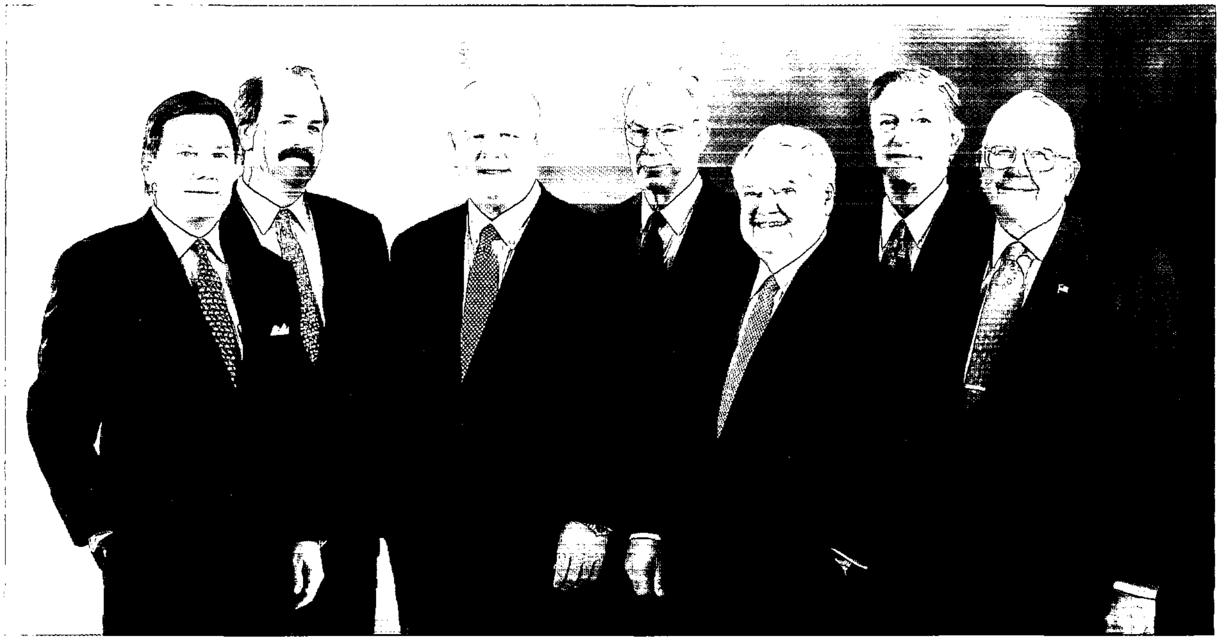
generation users switch back to gas when prices decline. Increased demand then nudges prices higher again. With the U.S. natural gas market expected to grow by 8 trillion cubic feet a day, or 36%, over the next decade, additional drilling will be required. More than 50% of the natural gas supplied today comes from wells drilled within the past two years. In this environment, Grey Wolf will benefit from the certain upturn in drilling in the nation's leading gas-producing territories.

Our People Make A Difference

As labor markets tightened in 2000 and early 2001, Grey Wolf's strategy of retaining experienced drillers and toolpushers and not cutting wages through market downturns proved that investments in people are as significant as investments in equipment. With qualified senior crews assuring efficient rig operations, the Company was able to quickly deploy more than 50 rigs in 18 months. The experienced crew members were also key in Grey Wolf's ability to earn and enter into long-term contracts.

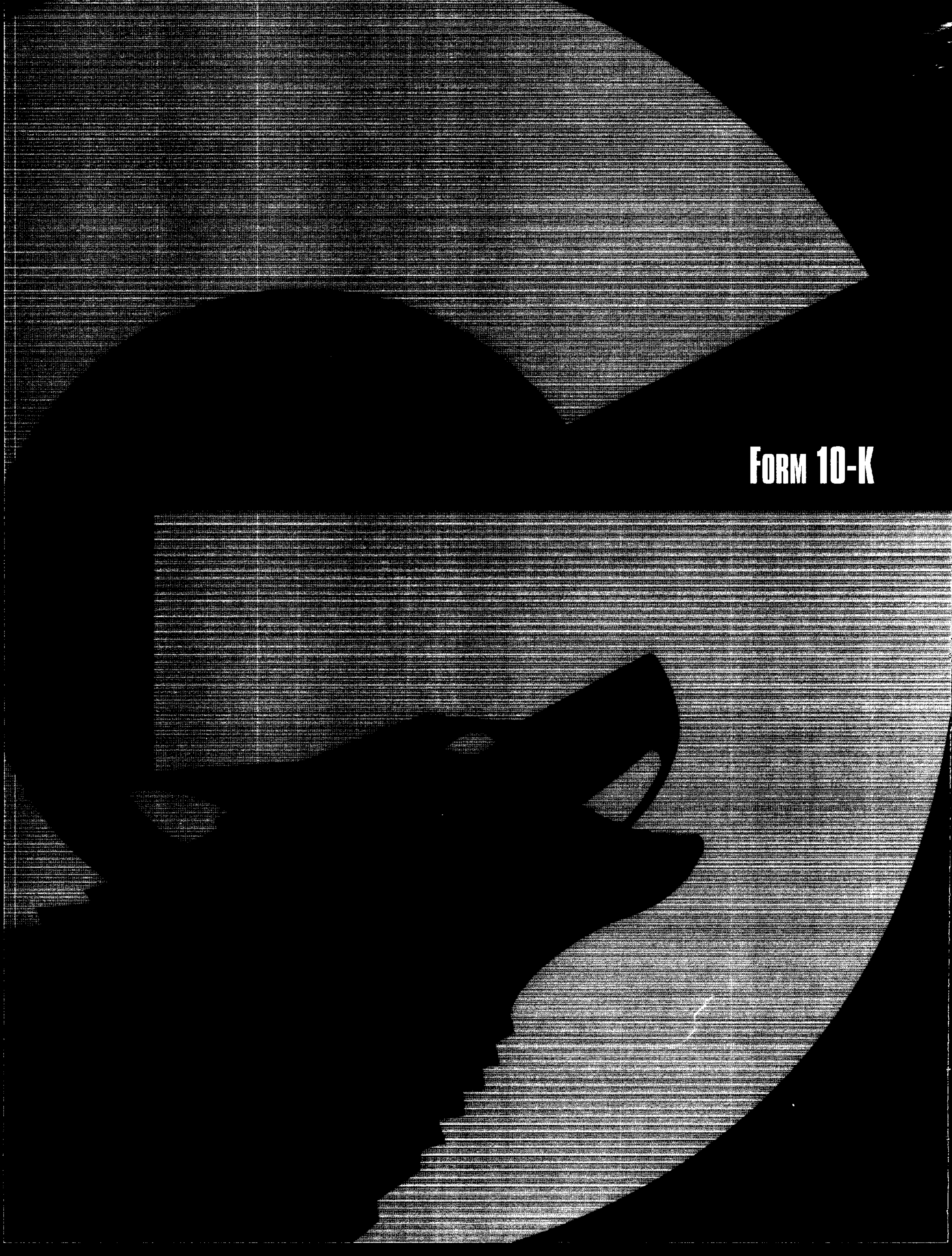
Retaining experienced crew members also enhances rig safety. The average cost of an injury that results in even one day of lost time is $28,000, according to the National Safety Council. So Grey Wolf strives for an accident-free work environment and applauds those rigs with outstanding safety performance, such as Rig 864, a 1,000 horsepower mobile rig operating in South Texas for a decade without a lost-time accident.

As it began to cold stack rigs in the last half of 2001, Grey Wolf moved swiftly to curtail expenses, but it remains committed to retaining experienced drillers and toolpushers. Grey Wolf's people provide a significant strategic advantage as the Company focuses on the quality end of the U.S. land drilling market where it continues to climb higher and drill deeper.



Directors: William T. Donovan, Steven A. Webster, Thomas P. Richards, William R. Ziegler, Robert E. Rose, Frank M. Brown, James K.B. Nelson

Officers: David W. Wehlmann, Gary D. Lee, Merrie S. Costley, Edward S. Jacob, III, Donald J. Guedry, Jr.



FORM 10-K

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

FORM 10-K

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2001

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 1-8226

GREY WOLF, INC.
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	74-2144774 (I.R.S. Employer Identification Number)
10370 Richmond Avenue, Suite 600 Houston, Texas (Address of principal executive offices)	77042 (Zip Code)

Registrant's telephone number, including area code: 713-435-6100

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

Title of each class	Name of each exchange on which registered
Common Stock, Par Value $0.10	American Stock Exchange
Rights to Purchase Junior Participating Preferred Stock, Par Value $1.00	American Stock Exchange

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

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 (229.405 under the Securities Exchange Act of 1934) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [✓]

At March 14, 2002, 180,795,661 shares of the Registrant's common stock were outstanding. The aggregate market value of the Registrant's voting stock held by non-affiliates (based upon the closing price on the American Stock Exchange on March 14, 2002 of $3.82 was approximately $643.0 million.

The following documents have been incorporated by reference into the Parts of this Report indicated: Certain sections of the Registrant's definitive proxy statement for the Registrant's 2001 Annual Meeting of shareholders which is to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 within 120 days of the Registrant's fiscal year ended December 31, 2001, are incorporated by reference into Part III hereof.

PART I

ITEM 1. BUSINESS

General

Grey Wolf, Inc. is a leading provider of contract land drilling services in the United States with a fleet of 121 rigs at March 14, 2002, of which 65 rigs are marketed. We have cold-stacked 34 rigs since the third quarter of 2001, bringing our inventory rig count to 56. Included in the marketed fleet is one non-owned rig that we operate for a third party. Our customers include independent producers and major oil and gas companies. We conduct all our operations through our subsidiaries.

Grey Wolf, Inc. is a Texas corporation formed in 1980. Our principal office is located at 10370 Richmond Avenue, Suite 600, Houston, TX 77042, and our telephone number is (713) 435-6100. Our website address is www.gwdrilling.com.

Business Strategy

Within the framework of a very cyclical industry, our strategy is to maximize shareholder value during periods of increasing demand and mitigate risk during periods of reduced demand. Our goal is to enter each phase of our industry's cycles in a stronger position. We attempt to achieve this by:

- delivering quality, value-added service to our customers;
- maintaining a leading position in our core markets;
- responding to market conditions by balancing dayrates with utilization;
- maintaining a high level of utilization for our marketed rigs;
- enhancing cash-flow through our turnkey and trucking operations and use of our top drives;
- controlling costs and maintaining capital spending discipline;
- maintaining a premium fleet of equipment with bias toward deep drilling for natural gas;
- using term contracts to provide sufficient cash flow to cover incremental capital expenditures for refurbishments on rigs under term contracts;
- using term contracts to mitigate the cyclical nature of dayrates;
- searching for new market opportunities where we believe our quality fleet of rigs would be able to generate attractive returns; and
- searching for potential acquisition candidates that we believe would be accretive.

Industry Overview

Our business is highly cyclical. It depends on the level of drilling activity by oil and gas exploration and production companies. The number of wells they chose to drill is strongly influenced by past trends in oil and gas prices, current prices, and their outlook for future oil and gas prices.

Since the end of the second quarter of 1999 until the third quarter of 2001, we, as well as the domestic land drilling industry in general, enjoyed sequential quarter over quarter improvement in operating and financial results. This improvement was driven by higher oil and natural gas prices which resulted in higher customer demand as reflected by higher rig counts. The average price of natural gas for 2000, based upon the New York Mercantile Exchange ("NYMEX") near month contract, was $4.32 per mmbtu and for the first nine months of 2001 was $4.51. The average NYMEX price of West Texas Intermediate crude for 2000 was $30.26 per barrel and for the first nine months of 2001 was $27.76. In addition, the domestic land rig count, as reported by industry sources, was 937 rigs at the end of 2000 and reached 1,114 rigs during July 2001.

Beginning in the third quarter of 2001 and continuing into 2002, we have seen a pronounced decline in customer demand reflected in the domestic land rig count due to lower commodity prices. Natural gas prices during the fourth quarter of 2001, based upon the NYMEX near month contract, averaged $2.69 per mmbtu and for the period from January 1, 2002 through March 14, 2002 averaged $2.33 per mmbtu. The average NYMEX price of West Texas Intermediate crude was $20.53 per barrel for the fourth quarter of 2001 and for the period of January 1, 2002 through

March 14, 2002 was $20.89. The domestic land rig count decreased from a high of 1,114 rigs during July 2001 to 743 rigs at the end of 2001 and 625 rigs on March 15, 2002.

Overall, the land drilling industry is still fragmented and very competitive. However, there has been significant consolidation within the industry since 1996 and further consolidation continued in 2001. Based on industry sources, we believe our combined market share was 20% in our four core markets at February 28, 2002.

Current Conditions

The year 2001 was by far the best year in the history of Grey Wolf. We averaged 85 rigs running for the year and generated earnings before interest, taxes, depreciation and amortization ("EBITDA") of $174.5 million. Net income was $68.5 million, or $.38 per diluted share.

Beginning in the third quarter of 2001, and continuing into 2002, we have seen a decline in the demand for land drilling services. Our customers, the exploration and production companies, are faced with lower revenues and cash flows due to lower commodity prices. The lower commodity prices and reduced demand for land drilling services has had a negative effect on our business. The average number of our rigs running has declined from 91 in the third quarter of 2001 to 68 in the fourth quarter of 2001 and to 58 from January 1, 2002 through March 8, 2002. In addition, our current bid rates without fuel and top drives have declined approximately 30% to $7,500 to $8,500 per rig day without fuel or top drives from a range of $10,000 to $13,000 per rig day in October of 2001.

Lower rig utilization and dayrates have negatively impacted our margins. Our average operating margin for the third quarter of 2001 was $6,971 per rig day compared to the fourth quarter of 2001 average of $5,337 per rig day. Our operating margin for the first quarter of 2002 is projected to be approximately $3,200 per rig day.

If current market conditions persist or deteriorate further, there will be an adverse effect on our business and results of operations.

Domestic Operations

At March 14, 2002, we had a rig fleet of 121 rigs, 65 of which were marketed and 56 were held in inventory. Included in the rig fleet is one rig that we do not own but operate for a third party. We currently conduct our operations in the following domestic drilling markets:

- Ark-La-Tex;
- Gulf Coast;
- Mississippi/Alabama;
- South Texas;
- Rocky Mountain; and
- West Texas.

We refer to the Ark-La-Tex, Gulf Coast, Mississippi/Alabama and South Texas markets as our "core markets," because the majority of our rigs are located in those markets. We conduct our operations primarily in core domestic markets which we believe have historically had greater utilization rates and dayrates than the combined total of all other domestic markets. This is in part due to the heavy concentration of natural gas reserves in these markets. During 2001, approximately 97% of the wells we drilled for our customers were drilled in search of natural gas. Larger natural gas reserves are typically found in deeper geological formations and generally require premium equipment and quality crews to drill the wells.

Ark-La-Tex Division. Our Ark-La-Tex division provides drilling services primarily in the Ark-La-Tex market which consists of Northeast Texas, Northern Louisiana and Southern Arkansas, and the Mississippi/Alabama market. We currently have 15 marketed rigs in this division which consist of 11 diesel electric rigs and four mechanical rigs. Our Ark-La-Tex division also operates a fleet of 26 trucks which are used exclusively to move our rigs.

We had an average of 27 rigs working in our Ark-La-Tex division during 2001. Daywork contracts generated approximately 93% of our revenues in this division, while turnkey and footage contracts generated the remaining 7%. The average revenue per rig day worked by the division during 2001 was $12,304. Based on industry sources, we had the third largest number of operating rigs in the Ark-La-Tex market, or a market share of approximately 14%, as of February 28, 2002.

Gulf Coast Division. Our Gulf Coast division provides drilling services in Southern Louisiana and along the upper Texas Gulf Coast. We currently have 18 marketed rigs in this division which consist of 17 diesel electric rigs and one mechanical rig.

We had an average of 27 rigs working in our Gulf Coast division during 2001. Daywork contracts generated approximately 78% of our revenues in this division, while turnkey and footage contracts generated the remaining 22%. The average revenue per rig day worked by the division during 2001 was $15,138. Based on industry sources, we had the largest number of operating rigs in this market, or a market share of approximately 29% as of February 28, 2002.

South Texas Division. We believe that trailer-mounted rigs and 1,500 to 2,000 horsepower diesel electric rigs are in highest demand in this market. Trailer-mounted rigs are relatively more mobile than conventional rigs, thus decreasing the time and expense to the customer of moving the rig to and from the drillsite. Under ordinary conditions, trailer-mounted rigs are capable of drilling an average of two 10,000 foot wells per month. We currently have 26 marketed rigs in this division, including one non-owned rig that we operate for a third party. The marketed rigs consist of 13 diesel electric rigs, eight mechanical trailer-mounted rigs, and five mechanical rigs. The South Texas division also operates a fleet of 35 trucks which are used exclusively to move our rigs.

We had an average of 30 rigs working in our South Texas division during 2001. Daywork contracts generated approximately 88% of our revenues in this division, while turnkey and footage contracts generated the remaining 12%. The average revenue per rig day worked by the division during 2001 was $12,973. Based on industry sources, we had the second largest number of operating rigs in this market, or a market share of approximately 21%, as of February 28, 2002.

Rocky Mountain Division. We began operations in the Rocky Mountain market in June 2001 under a two-year term contract for our ultra-deep drilling Rig 558. In October 2001, we deployed a second rig into the market under a one-year term contract. Both rigs are diesel electric rigs and have been drilling in Wyoming since inception of operations in this division. These two term contracts generated 100% of our revenues in this division and the average revenue per rig day worked by the division during 2001 was $15,574. The presence of these rigs provide us with an established operating base in this market which could allow for further expansion opportunities.

West Texas Division. In May 2001, we signed a two-year term contract for a 3,000 horsepower rig to drill in West Texas. This rig is being upgraded from inventory and is expected to go to work in the second quarter of 2002. Excluding this rig, we currently have four marketed rigs in this division and all four are diesel electric rigs drilling deep and/or horizontal wells. We began operations in West Texas in October 2001 for a large independent oil and gas company on a well to well contract basis. The other three rigs began operations in either January or February 2002. The presence of these rigs provide us with an established operating base in this market which could allow for further expansion opportunities.

Closing of Venezuelan Operations

During the second quarter of 2001, we moved our five Venezuela rigs to the United States, and in the third quarter of 2001 sold three of the five rigs for $1.3 million. We no longer have operations or operating assets in international markets.

Inventory Rigs

We categorize a rig that is not currently being marketed by us as an "inventory rig." At March 14, 2002, 56 of our rigs, or approximately 46% of our rig fleet, were inventory rigs. Within the framework of our business strategy and as demand warrants, we plan to reactivate inventory rigs. The actual cost to reactivate these rigs will depend on the specific customer requirements and the extent to which we choose to upgrade the rigs.

The actual number of inventory rigs reactivated during 2002, if any, and in the future will depend on many factors, including our estimation of existing and anticipated demand and dayrates, our success in bidding for domestic contracts, including term contracts, and the timing of the reactivations.

Contracts

Our contracts for drilling oil and gas wells are obtained either through competitive bidding or as a result of negotiations with customers. Contract terms offered by us are generally dependent on the complexity and risk of operations, on-site drilling conditions, type of equipment used and the anticipated duration of the work to be performed. Generally, domestic drilling contracts are for a single well. The majority of domestic drilling contracts are typically subject to termination by the customer on short notice, usually upon payment of a fee. However, we have entered into a number of term contracts to provide drilling services on a daywork basis with terms ranging in length from six months to two years. These term contracts include a per rig day termination rate approximately equal to our daily margin on each contract. Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis.

Daywork Contracts. Under daywork drilling contracts, we provide a drilling rig with required personnel to our customer who supervises the drilling of the well. We are paid based on a fixed rate per day while the rig is utilized. Daywork drilling contracts specify the equipment to be used, the size of the hole and the depth of the well. Under a daywork drilling contract, the customer bears a large portion of out-of-pocket costs of drilling and we generally bear no part of the usual risks associated with drilling, such as time delays for various reasons, including stuck drill pipe or blowout.

Turnkey Contracts. Under a turnkey contract, we contract to drill a well to an agreed-upon depth under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. We provide technical expertise and engineering services, as well as most of the materials required for the well, and are compensated when the contract terms have been satisfied. Turnkey contracts afford an opportunity to earn a higher return than would normally be available on daywork or footage contracts if the contract can be completed successfully without complications.

The risks to us under a turnkey contract are substantially greater than on a daywork basis because we assume most of the risks associated with drilling operations generally assumed by the operator in a daywork contract, including the risk of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors' services, supplies, cost escalation and personnel. We employ or contract for engineering expertise to analyze seismic, geologic and drilling data to identify and reduce many of the drilling risks assumed by us. We use the results of this analysis to evaluate the risks of a proposed contract and seek to account for such risks in our bid preparation. We believe that our operating experience, qualified drilling personnel, risk management program, internal engineering expertise and access to proficient third party engineering contractors have allowed us to reduce the risks inherent in turnkey drilling operations. We also maintain insurance coverage against some but not all drilling hazards.

Footage Contracts. Under footage contracts, we are paid a fixed amount for each foot drilled, regardless of the time required or the problems encountered in drilling the well. We typically pay more of the out-of-pocket costs associated with footage contracts than under daywork contracts. Similar to a turnkey contract, the risks to us on a footage contract are greater because we assume most of the risks associated with drilling operations generally assumed by the operator in a daywork contract, including the risk of blowout, loss of hole, stuck drill pipe, machinery breakdowns, abnormal drilling conditions and risks associated with subcontractors' services, supplies, cost escalation and personnel. As with turnkey contracts, we manage this additional risk through the use of engineering expertise and bid the footage contracts accordingly. We also maintain insurance coverage against certain drilling hazards.

Customers and Marketing

Our contract drilling customers include independent producers and major oil and gas companies. We primarily market our drilling rigs on a regional basis through employee sales representatives. These sales representatives utilize personal contacts and industry periodicals and publications to determine which operators are planning to drill oil and gas wells in the immediate future. Once we have been placed on the "bid list" for an operator, we will typically be given the opportunity to bid on all future wells for that operator in the area.

From time to time we also enter into informal, nonbinding commitments with our customers to provide drilling rigs for future periods at agreed upon rates plus fuel and mobilization charges, if applicable, and escalation provisions. This practice is customary in the land drilling business during times of tightening rig supply. Although neither we nor the customer are legally required to honor these commitments, we strive to satisfy such commitments in order to maintain good customer relations.

Term Contracts

During late 2000 and 2001, we entered into a number of term contracts with our customers with terms ranging in length from six months to two years. The practical effect of these term contracts is to protect us for the duration of the contract from having the rig remain idle and from unexpected declines in dayrates for our rigs. Conversely, our customers benefit from term contracts by the assured availability of a rig to meet their drilling schedule, and from contractual protection against exposure to rapid increases in dayrates under well-by-well drilling contracts. These term contracts are priced on a fixed, dayrate basis which allow us to recover the incremental capital expenditures on the rigs under term contracts and provide an acceptable rate of return on capital employed. The term contracts also contain termination provisions which require our customers, upon cancellation of a contract, to pay an amount that approximates our operating margin for the remaining days under contract. We intend to continue to enter into additional term contracts from time to time based upon market conditions. However, customer interest in term contracts are lower during periods of overall lower demand.

We expect that our 21 term contracts will contribute substantially to our revenues in 2002. An average of approximately 16 rigs and a total of 6,000 days are currently contracted for under term contracts in 2002, which are expected to generate approximately $83.6 million of revenues for us in 2002. Of our current term contracts, 11 have contract terms extending into 2003 that provide for a total of 1,350 days of drilling and revenues of approximately $20.3 million in 2003.

We also expect our term contracts to contribute substantially to our average per rig day operating margin for 2002. Rigs under term contracts are expected to provide us with an approximate per rig day operating margin of $7,000 in 2002. We expect that our combined average operating margin will be approximately $3,200 per rig day in the first quarter of 2002.

Insurance

Our operations are subject to the many hazards inherent in the drilling business, including, for example, blowouts, cratering, fires, explosions and adverse weather. These hazards could cause personal injury, death, suspend drilling operations or seriously damage or destroy the equipment involved and could cause substantial damage to producing formations and surrounding areas. Damage to the environment could also result from our operations, particularly through oil spillage and extensive, uncontrolled fires. As a protection against operating hazards, we maintain insurance coverage, including comprehensive general liability and commercial contract indemnity, commercial umbrella and workers' compensation insurance, property casualty insurance on our rigs and drilling equipment, and "control of well" insurance.

Our third party liability insurance coverage under our general policies is $1.0 million per occurrence, with a deductible of $100,000 per occurrence. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. However, our insurance may not be sufficient to protect us against liability for all consequences of well disasters, extensive fire damage or damage to the environment.

Our workers' compensation insurance coverage is $1.0 million per occurrence with a deductible of $250,000 per occurrence. We believe that we are adequately insured for workers' compensation. However, if significant and multiple workers' compensation claims are filed, we could incur significant expenses, which could have an adverse effect on our financial condition and results of operations.

We have commercial umbrella, or excess liability insurance, to cover general liability and workers' compensation claims which are higher than the maximum coverage provided under those policies. Our excess liability insurance covers up to a maximum of $75.0 million in the aggregate and have deductibles per occurrence of $50,000 on the first $10.0 million of coverage and $50,000 on the remaining $65.0 million of coverage.

Our insurance coverage for property damage to our rigs and drilling equipment is based on our estimate of the cost of comparable used equipment to replace the insured property. There is a deductible on rigs of $850,000 in the aggregate over an eighteen month policy period (with a sublimit of up to $575,000 per claim in respect of such aggregate limit) to be comprised of losses otherwise recoverable thereafter in excess of a $50,000 maintenance deductible. There is a $10,000 deductible per occurrence on other equipment.

We also maintain insurance coverage to protect against certain hazards inherent in our turnkey and footage contract drilling operations. This insurance covers "control of well" (including blowouts above and below the surface), cratering, seepage and pollution and care, custody and control. Our current insurance provides $500,000 coverage per occurrence for care, custody and control, and coverage per occurrence for control of well, cratering, seepage and pollution associated with drilling operations of either $10.0 million or $20.0 million, depending upon the area in which the well is drilled and its target depth. Each form of coverage provides for a deductible that we must meet, as well as a maximum limit of liability. Each casualty is an occurrence, and there may be more than one such occurrence on a well, each of which would be subject to a separate deductible.

Significant Acquisitions and Sales

Over the period from August 1996 through February 1998, we completed 13 transactions acquiring 100 land drilling rigs, of which 67 were marketed and 33 were inventoried at the time of acquisition. During that same period of time, we sold six land drilling rigs and our 65% interest in a joint venture owning nine additional rigs.

Certain Risks

Our business is subject to a number of risks and uncertainties, the most important of which are listed below:

Our business can be adversely affected by low oil and gas prices and expectations of low prices.

As a supplier of land drilling services, our business depends on the level of drilling activity by oil and gas exploration and production companies operating in the geographic markets where we operate. The number of wells they choose to drill is strongly influenced by past trends in oil and gas prices, current prices, and their outlook for future oil and gas prices. Low oil and gas prices, or the perception among oil and gas companies that future prices are likely to decline, can materially and adversely affect us in many ways, including:

- our revenues, cash flows and earnings;
- our customers may seek to terminate, renegotiate or fail to honor our term drilling contracts;
- the fair market value of our rig fleet which in turn could trigger a writedown for accounting purposes;
- our ability to maintain or increase our borrowing capacity;
- our ability to obtain additional capital to finance our business and make acquisitions, and the cost of that capital; and
- our ability to retain skilled rig personnel who we would need in the event of an upturn in the demand for our services.

Oil and gas prices have been volatile historically and, we believe, will continue to be so in the future. Many factors beyond our control affect oil and gas prices, including:

- weather conditions in the United States and elsewhere;
- economic conditions in the United States and elsewhere;
- actions by OPEC, the Organization of Petroleum Exporting Countries;
- political stability in the Middle East and other major producing regions;
- governmental regulations, both domestic and foreign;
- the pace adopted by foreign governments for exploration of their national reserves;
- the price of foreign imports of oil and gas; and
- the overall supply and demand for oil and gas.

We operate in a highly competitive, fragmented industry in which price competition is intense.

The drilling contracts we compete for are usually awarded on the basis of competitive bids. Pricing and rig availability are the primary factors considered by our potential customers in determining which drilling contractor to select. We believe other factors are also important. Among those factors are:

- the type and condition of drilling rigs;
- the quality of service and experience of rig crews;
- the safety record of the rig;
- the offering of ancillary services; and
- the ability to provide drilling equipment adaptable to, and personnel familiar with, new technologies and drilling techniques.

While we must generally be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment, the safety record of our rigs and the experience of our rig crews to differentiate us from our competitors. This strategy is less effective as lower demand for drilling services intensifies price competition and makes it more difficult for us to compete on the basis of factors other than price. In all of the markets in which we compete, an over supply of rigs can cause greater price competition.

Contract drilling companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling services improves in a region where we operate, our competitors might respond by moving in suitable rigs from other regions. An influx of rigs from other regions could rapidly intensify competition and make any improvement in demand for drilling rigs short-lived.

We face competition from competitors with greater resources.

Certain of our competitors have greater financial and human resources than do we. Their greater capabilities in these areas may enable them to:

- better withstand periods of low rig utilization;
- compete more effectively on the basis of price and technology;
- retain skilled rig personnel; and
- build new rigs or acquire and refurbish existing rigs so as to be able to place rigs into service more quickly than us in periods of high drilling demand.

Our drilling operations involve inherent risks of loss which if not insured or indemnified against could adversely affect our results of operations and financial condition.

Our business is subject to the many hazards inherent in the land drilling business including the risks of:

- blowouts;
- fires and explosions;
- collapse of the borehole;
- lost or stuck drill strings; and
- damage or loss from natural disasters.

We attempt to obtain indemnification from our customers by contract for certain of these risks under daywork contracts but are not always able to do so. We also seek to protect ourselves from some but not all operating hazards through insurance coverage.

If these drilling hazards occur they can produce substantial liabilities to us from, among other things:

- suspension of drilling operations;
- damage to the environment;
- damage to, or destruction of our property and equipment and that of others;
- personal injury and loss of life; and
- damage to producing or potentially productive oil and gas formations through which we drill.

The indemnification we receive from our customers and our own insurance coverage may not, however, be sufficient to protect us against liability for all consequences of disasters, personal injury and property damage. Additionally, our insurance coverage generally provides that we bear a portion of the claim through substantial insurance coverage deductibles. The premiums we pay for insurance policies are also subject to substantial increase based upon our claims history and outside economic events that affect the insurance industry in general, which may increase our operating costs. We can offer no assurance that our insurance or indemnification arrangements will adequately protect us against liability from all of the hazards of our business. We are also subject to the risk that we may be unable to obtain or renew insurance coverage of the type and amount we desire at reasonable rates. If we were to incur a significant liability for which we were not fully insured or indemnified it could have a material adverse effect on our financial position and results of operations.

Our operations are subject to environmental laws that may expose us to liabilities for noncompliance which may adversely affect us.

Many aspects of our operations are subject to domestic laws and regulations. For example, our drilling operations are typically subject to extensive and evolving laws and regulations governing:

- environmental quality;
- pollution control; and
- remediation of environmental contamination.

Our operations are often conducted in or near ecologically sensitive areas, such as wetlands which are subject to special protective measures and which may expose us to additional operating costs and liabilities for noncompliance with applicable laws. The handling of waste materials, some of which are classified as hazardous substances, is a necessary part of our operations. Consequently, our operations are subject to stringent regulations relating to protection of the environment and waste handling which may impose liability on us for our own noncompliance and, in addition, that of other parties without regard to whether we were negligent or otherwise at fault. We may also be exposed to environmental or other liabilities originating from businesses and assets which we purchased from others. Compliance with applicable laws and regulations may require us to incur significant expenses and capital expenditures which could have a material and adverse effect on our operations by increasing our expenses and limiting our future contract drilling opportunities.

Volatility in oil and gas prices can adversely affect our business.

Volatility in oil and gas prices can produce wide swings in the levels of overall drilling activity in the markets we serve and affect the demand for our drilling services and the dayrates we can charge for our rigs. Pronounced downturns in oil and gas prices can adversely affect our business.

We believe our operating and financial performance illustrates this risk. Oil and gas prices generally dropped beginning in late 1997, with generally lower commodity prices extending well into 1999. Beginning in the first quarter of 1998, drilling activity in the markets we serve also dropped significantly, and we experienced significant declines both in the average number of rigs working and in the rates we could charge for them. During 2000 and the first nine months of 2001, market conditions improved, with higher commodity prices, dayrates, and rig utilization. However, commodity prices dropped again in mid-2001 which adversely affected drilling activity and dayrates. The average number of our rigs working in the third quarter of 2001 was 91 but declined to 68 in the fourth quarter of 2001and 58 for the period from January 1, 2002 to March 8, 2002. Our operating margin per rig day was $6,971 in the third quarter of 2001 but fell to $5,337 in the fourth quarter of 2001 and is projected to be approximately $3,200 for the first quarter of 2002.

Future demand for our rigs may continue to decline and we can offer you no assurance otherwise. If drilling activity increases in the areas where we operate, we cannot assure you that demand for our rigs will also increase.

In addition to trade liabilities, we have $250.0 million of principal amount indebtedness under our senior notes with semi-annual interest payments of approximately $11.1 million.

We are indebted for a total of $250.0 million in principal amount under our 8⅞% Senior Notes due 2007. Semi-annual interest payments on the senior notes of approximately $11.1 million are due on January 1 and July 1 of each year. Our operating activities provided net cash sufficient to pay our debt service obligations for the year ended December 31, 2001; however, there can be no assurances that we will be able to generate sufficient cash flow in the future.

Our ability in the future to meet our debt service obligations and reduce our total indebtedness will depend on a number of factors including:

- oil and gas prices;
- demand for our drilling services;
- whether our business strategy is successful; and
- other financial and business factors that affect us.

Many of these factors are beyond our control.

If we do not generate sufficient cash flow to pay debt service and repay principal in the future, we will likely be required to use one or more of the following measures:

- further diminish our cash balances;
- use our existing credit facility;
- obtain additional external financing;
- refinance our indebtedness; and
- sell our assets.

We have had only two profitable years since 1991.

While we returned to profitability during 2001, we have a history of losses with our only profitable years since 1991 being 1997 and 2001 in which we had net income of $10.2 million and $68.5 million, respectively. Whether we are able to be profitable in the future will depend on many factors, but primarily on whether we are able to maintain high utilization rates for our rigs and the rates we charge for them. Whether we can achieve those goals will largely depend on oil and gas prices which are beyond our control.

Unexpected cost overruns on our turnkey and footage drilling jobs could adversely affect us.

We have historically derived a significant portion of our revenues from turnkey and footage drilling contracts and we expect that they will continue to represent a significant component of our revenues. The occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey and footage jobs could have a material adverse effect on our financial position and results of operations. Under a typical turnkey or footage drilling contract, we agree to drill a well for our customer to a specified depth and under specified conditions for a fixed price. We typically provide technical expertise and engineering service, as well as most of the equipment required for the drilling of turnkey and footage wells. We often subcontract for related services. Under typical turnkey drilling arrangements, we do not receive progress payments and are entitled to be paid by our customer only after we have performed the terms of the drilling contract in full. For these reasons, the risk to us under turnkey and footage drilling contracts is substantially greater than for wells drilled on a daywork basis because we must assume most of the risks associated with drilling operations that are generally assumed by our customer under a daywork contract. Although we attempt to obtain insurance coverage to reduce certain of the risks inherent in our turnkey and footage drilling operations, we can offer no assurance that adequate coverage will be obtained or will be available in the future.

We could be adversely affected if we lost the services of certain of our senior managers.

Our business is dependent to a significant extent on a small group of our executive management personnel. The loss of any one of these individuals could have a material adverse effect on our financial condition and results of operations.

Our indentures and credit agreements may prohibit us from participation in certain transactions that we may consider advantageous.

The indentures under which we issued our senior notes contain restrictions on our ability and the ability of certain of our subsidiaries to engage in certain types of transactions. These restrictive covenants may adversely affect our ability to pursue business acquisitions and perform rig refurbishments. These include covenants prohibiting or limiting our ability to:

- incur additional indebtedness;
- pay dividends or make other restricted payments;
- repurchase our equity securities;
- sell material assets;
- grant or permit liens to exist on our assets;
- enter into sale and lease-back transactions;
- enter into certain mergers, acquisitions and consolidations;
- make certain investments;
- enter into transactions with related persons; and
- engage in lines of business unrelated to our core land drilling business.

Our senior secured credit facility also contains covenants restricting our ability and our subsidiaries' ability to undertake many of the same types of transactions, and when certain conditions are met, contains financial ratio covenants. They may also limit our ability to respond to changes in market conditions. Our ability to meet the financial ratio covenants of our credit agreement and indentures can be affected by events and conditions beyond our control and we may be unable to meet those tests.

Our senior secured credit facility contains default terms that effectively cross default with the indentures covering our senior notes. If we breach the covenants in the indentures it could cause our default under our senior notes, and also under our senior secured credit agreement, and possibly under other then outstanding debt obligations owed by us or our subsidiaries. If the indebtedness under our senior secured credit agreement or other indebtedness owed by us or our subsidiaries is more that $10.0 million and is not paid when due, or is accelerated by the holders of the debt, then an event of default under the indenture covering our senior notes would occur. If circumstances arise in which we are in default under our various credit agreements, our cash and other assets may be insufficient to repay our indebtedness and that of our subsidiaries.

We could be adversely affected if shortages of equipment, supplies or personnel occur.

While we are not currently experiencing any shortages, from time to time there have been shortages of drilling equipment and supplies which we believe could reoccur. During periods of shortages, the cost and delivery times of equipment and supplies are substantially greater. In the past, in response to such shortages, we have formed alliances with various suppliers and manufacturers that enabled us to reduce our exposure to price increases and supply shortages. Although we have formed many informal supply alliances with equipment manufacturers and suppliers and are attempting to establish arrangements to assure adequate availability of certain necessary equipment and supplies on satisfactory terms, there can be no assurance that we will be able to do so or to maintain existing alliances. Shortages of drilling equipment or supplies could delay and adversely affect our ability to return to service our inventory rigs and obtain contracts for our marketed rigs, which could have a material adverse effect on our financial condition and results of operations.

Although we have not encountered material difficulty in hiring and retaining qualified rig crews, such shortages have occurred in the past in our industry. We may experience shortages of qualified personnel to operate our rigs, which could have a material adverse effect on our financial condition and results of operations.

Our existing dividend policy and contractual restrictions limit our ability to pay dividends.

We have never declared a cash dividend on our common stock and do not expect to pay cash dividends on our common stock for the foreseeable future. We expect that all cash flow generated from our operations in the foreseeable future will be retained and used to develop or expand our business, pay debt service and reduce outstanding indebtedness. Furthermore, the terms of our senior secured credit facility prohibit the payment of dividends without the prior written consent of the lenders and the terms of the indentures under which our senior notes are issued also restrict our ability to pay dividends under certain conditions.

Certain provisions of our organizational documents, securities and credit agreements have anti-takeover effects which may prevent our shareholders from receiving the maximum value for their shares.

Our articles of incorporation, bylaws and securities and credit agreements contain certain provisions intended to delay or prevent entirely a change of control transaction not supported by our board of directors, or which may have that general effect. These measures include:

- classification of our board of directors into three classes, with each class serving a staggered three year term;
- giving our board of directors the exclusive authority to adopt, amend or repeal our bylaws and thus prohibiting shareholders from doing so;
- requiring our shareholders to give advance notice of their intent to submit a proposal at the annual meeting; and
- limiting the ability of our shareholders to call a special meeting and act by written consent.

Additionally, the indentures under which our senior notes are issued, require us to offer to repurchase all senior notes then outstanding at a purchase price equal to 101% of the principal amount of the senior notes plus accrued and unpaid interest to the date of purchase in the event that we become subject to a change of control, as defined in the indentures. This feature of the indentures could also have the effect of discouraging potentially attractive change of control offers.

In addition, we have adopted a shareholder rights plan which may have the effect of impeding a hostile attempt to acquire control of us.

Large amounts of our common stock may be resold into the market in the future which could cause the market price of our common stock to drop significantly, even if our business is doing well.

If we issue a significant amount of common stock, convertible preferred stock or warrants, the market price of our common stock may be adversely affected.

As of March 14, 2002, 180.8 million shares of our common stock were issued and outstanding. In addition, as of March 14, 2002, we had issued options to purchase 9.7 million shares of common stock and these options are currently exercisable for 3.2 million shares of common stock. The market price of our common stock could drop significantly if future sales of substantial amounts of our common stock occur, or if the perception exists that substantial sales may occur.

Employees

At March 14, 2002, we had approximately 1,700 employees. None of our employees are subject to collective bargaining agreements, and we believe our employee relations are satisfactory.

Forward-Looking Statements

This Annual Report on Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this report are forward-looking statements, including statements regarding the following:

- business strategy;
- demand for our services;
- 2002 rig activity and financial results;
- reactivation of inventory rigs;
- projected daily margins;
- wage rates;
- depreciation and capital expenditures in 2002; and
- anticipated operating and financial results with respect to our term drilling contracts.

Although we believe the expectations and beliefs reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include:

- fluctuations in prices and demand for oil and gas;
- fluctuations in levels of oil and gas exploration and development activities;
- fluctuations in the demand for contract land drilling services;
- the existence and competitive responses of our competitors;
- attempts by our customers to terminate, renegotiate, or fail to honor term drilling contracts;
- technological changes and developments in the industry;
- the existence of operating risks inherent in the contract land drilling industry;
- U.S. and global economic conditions;
- the availability and terms of insurance coverage;
- the ability to attract and retain qualified personnel; and
- unforseen operating costs such as cost for environmental remediation and turnkey cost overruns.

Our forward-looking statements speak only as of the date specified in such statements or, if no date is stated, as of the date of this report. Grey Wolf expressly disclaims any obligation or undertaking to release publicly any updates or revisions to any forward-looking statement contained in this report to reflect any change in our expectations or with regard to any change in events, conditions or circumstances on which our forward-looking statements are based. Please refer to "Certain Risks" above for additional information concerning risk factors that could also cause actual results to differ from the forward-looking statements.

ITEM 2. PROPERTIES

Drilling Equipment

A land drilling rig consists of engines, drawworks, mast, substructure, pumps to circulate drilling fluid, blowout preventers, drill pipe and related equipment. The actual drilling capacity of a rig may be less than its rated drilling capacity due to numerous factors, including the length of the drill pipe on the rig. The intended well depth and the drill site conditions determine the amount of drill pipe and other equipment needed to drill a well. Generally, land rigs operate domestically with crews of four to six people.

Our rig fleet consists of several rig types to meet the demands of our customers in each of the markets we serve. Our rig fleet consists of two basic types of drilling rigs, mechanical and diesel electric. Mechanical rigs transmit power generated by a diesel engine directly to an operation (for example the drawworks or mud pumps on a rig) through a compound consisting of chains, gears and hydraulic clutches. Diesel electric rigs are further broken down into two subcategories, direct current rigs and SCR rigs. Direct current rigs transmit the power generated by a diesel engine to a direct current generator. This direct current electrical system then distributes the electricity generated to direct current motors on the drawworks and mud pumps. An SCR rig's diesel engines drive alternating current generators and this alternating current can be transmitted to use for rig lighting and rig quarters or converted to direct current to drive the direct current motors on the rig. We own 12 direct current diesel electric rigs and 50 SCR diesel electric rigs. We also own 18 mechanical rigs and one diesel electric rig that are trailer-mounted for greater mobility.

We also utilize top drives in our drilling operations. A top drive allows drilling with 90-foot lengths of drill pipe rather than 30-foot lengths, thus reducing the number of required connections. A top drive also permits rotation of the drill string while tripping in or out of the hole. These characteristics increase drilling speed, personnel safety and drilling efficiency, and reduce the risk of the drill string sticking during operations. At March 14, 2002, we owned 13 top drives.

We generally deploy our rig fleet among our divisions based on the types of rigs preferred by our customers for drilling in the geographic markets served by our divisions. The following table summarizes the rigs we own as of March 14, 2002:

	Maximum Rated Depth Capacity				
	Under 10,000'	10,000' to 14,999'	15,000' to 19,999'	20,000' and Deeper	Total
Marketed					
Ark-La-Tex					
Diesel Electric	–	1	5	5	11
Mechanical	–	1	3	–	4
Gulf Coast					
Diesel Electric	–	–	1	16	17
Mechanical	–	–	1	–	1
South Texas					
Diesel Electric	–	1	4	7	12 (1)
Trailer-Mounted	–	8	–	–	8
Mechanical	–	4	–	1	5
Rocky Mountain					
Diesel Electric	–	–	–	2	2
West Texas					
Diesel Electric	–	–	2	2	4
Total Marketed	–	15	16	33	64
Inventory					
Diesel Electric	–	–	–	16	16
Trailer-Mounted	2	8	–	1	11
Mechanical	–	14	9	6	29
Total Inventory	2	22	9	23	56
Total Rig Fleet	2	37	25	56	120

(1) Excludes one rig which we operate for a third party.

Facilities

The following table summarizes our significant real estate:

Location	Interest	Uses
Houston, Texas	Leased	Executive Offices
Alice, Texas	Owned	Field Office, Rig Yard, Truck Yard
Eunice, Louisiana	Owned	Field Office, Rig Yard
Fillmore, Louisiana	Owned	Rig Yard
Oklahoma City, Oklahoma	Owned	Rig Yard
Shreveport, Louisiana	Leased	Field Office
Shreveport, Louisiana	Owned	Rig Yard
Casper, Wyoming	Leased	Field Office
Midland, Texas	Leased	Field Office

We lease approximately 22,700 square feet of office space in Houston, Texas for our principal executive offices at a cost of approximately $39,600 per month. We believe that all our facilities are in good operating condition and that they are adequate for their present uses.

ITEM 3. LEGAL PROCEEDINGS

We are involved in litigation incidental to the conduct of our business, none of which we believe is, individually or in the aggregate, material to our consolidated financial condition or results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED SHAREHOLDER MATTERS

Market Data

Our common stock is listed and traded on the American Stock Exchange ("AMEX") under the symbol "GW." The following table sets forth the high and low closing prices of our common stock on the AMEX for the periods indicated:

	High	Low
Period from January 1, 2002 to March 14, 2002	$ 4.0700	$ 2.6900
Year Ended December 31, 2001:		
Quarter ended March 31, 2001	6.9600	5.0625
Quarter ended June 30, 2001	6.8700	3.7700
Quarter ended September 30, 2001	3.7300	1.7500
Quarter ended December 31, 2001	3.3100	1.7600
Year Ended December 31, 2000:		
Quarter ended March 31, 2000	4.4375	2.8125
Quarter ended June 30, 2000	5.3125	3.1250
Quarter ended September 30, 2000	5.7500	3.9375
Quarter ended December 31, 2000	5.8750	3.6250

We have never declared or paid cash dividends on our common stock and do not expect to pay cash dividends in 2002 or for the foreseeable future. We anticipate that all cash flow generated from operations in the foreseeable future will be retained and used to develop or expand our business, pay debt service and reduce outstanding indebtedness. Any future payment of cash dividends will depend upon our results of operations, financial condition, cash requirements and other factors deemed relevant by our board of directors.

The terms of our credit facility prohibit the payment of dividends without the prior written consent of the lender and the terms of the Indentures under which our senior notes are issued also restrict our ability to pay dividends under certain conditions.

On March 14, 2002, the last reported sales price of our common stock on the AMEX was $3.82 per share.

ITEM 6. SELECTED FINANCIAL DATA

(Amounts in thousands, except per share amounts)

	Years Ended December 31,				
	2001	2000	1999	1998	1997
Revenues	$ 421,501	$ 269,334	$ 147,203	$ 240,979	$ 215,923
Net income (loss)	68,453	(8,523)	(41,262)	(83,213)	10,218
Net income (loss) per common share - basic and diluted:	.38	(.05)	(.25)	(.50)	.07
Total assets	623,876	510,866	452,846	501,303	533,752
Senior notes & other long-term debt	250,695	249,851	249,962	250,527	176,225
Series A Preferred Stock - Mandatorily Redeemable	–	–	–	305	305

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

The following discussion should be read in conjunction with our consolidated financial statements included elsewhere herein. All significant intercompany transactions have been eliminated.

General

We are a leading provider of contract land drilling services in the United States with a fleet of 121 rigs, of which 65 rigs are currently marketed. We recently cold-stacked 34 rigs, bringing our inventory rig count to 56. Included in the marketed fleet is one non-owned rig that we operate for a third party.

Rig Activity

Since the end of the second quarter of 1999 we, as well as the domestic land drilling industry in general, enjoyed sequential quarter over quarter improvement in operating and financial results. This improvement was driven by higher oil and natural gas prices which resulted in higher customer demand as reflected by higher rig counts. However, we saw a pronounced decline in customer demand reflected in the number of rigs running due to lower commodity prices beginning late in the third quarter of 2001. This trend has continued into the first quarter of 2002. At March 14, 2002, we had 56 rigs working. The table below shows the average number of our rigs working in our operating markets during the periods indicated:

1999	2000					2001					2002
Full Year	Q-1	Q-2	Q-3	Q-4	Full Year	Q-1	Q-2	Q-3	Q-4	Full Year	Q-1 to Date
45	61	65	77	83	71	88	92	91	68	85	58

Drilling Contract Bid Rates

Dayrates are driven by utilization and with the declining number of rigs running, we have also seen a drop in dayrates. Our current daywork bid rates are between $7,500 and $8,500 per rig day without fuel or top drives. This is a decline from the leading edge bid rates of $10,000 to $13,000 per rig day in October 2001and from the high of $13,500 to $17,000 per rig day in April 2001. We currently own 13 top drives for which our current bid rates are $1,500 per rig day. Bid rates for our top drives reached $2,000 per rig day in mid-2001. Bid rates for our top drives are in addition to the above stated bid rates for our rigs.

Term Contracts

An integral part of our strategy in 2001 was to seek out long term contracts with our customers to help ensure an income stream in the event of lower commodity prices, to recover capital costs of refurbishment plus an acceptable return, and to be able to give our customers a dedicated rig for their drilling programs at a competitive rate. All nine of the rigs returned to service in 2001 and the one rig to be returned to service in 2002 were reactivated under term contracts. These term contracts have original terms ranging in length from one to two years and contain termination provisions which require our customers, upon cancellation of a contract, to pay an amount that approximates our operating margin for the remaining days under the contract.

Twenty rigs are currently working under term contracts and one additional rig will go to work under a term contract in the second quarter of 2002. We expect that our 21 term contracts will contribute substantially to our revenues in 2002. An average of approximately 16 rigs and a total of 6,000 days are currently contracted for under term contracts in 2002, which are expected to generate approximately $83.6 million of revenues for us in 2002. Of our current term contracts, 11 have contract terms extending into 2003 that provide for a total of 1,350 days of drilling and revenues of approximately $20.3 million in 2003.

We also expect our term contracts to contribute substantially to our average per rig day operating margin for 2002. Rigs under term contracts are expected to provide us with an approximate operating margin of $7,000 per rig day in 2002. We expect that our combined average operating margin will be approximately $3,200 per rig day in the first quarter of 2002.

As discussed previously, we have seen a weakening in demand and believe that our current term contracts will mitigate a portion of the financial risk associated with this lower demand.

Turnkey and Footage Contract Activity

Revenue generated from turnkey and footage contracts was approximately 12% of total revenue in the fourth quarter of 2001, compared with 15% during the third quarter of 2001 and 18% during the fourth quarter of 2000. For the years ended December 31, 2001 and 2000, turnkey and footage contracts represented 14% and 30% of total revenue, respectively. The percentage of days worked on turnkey and footage contracts was 5% of total days worked in the fourth quarter of 2001 compared to 7% in the third quarter of 2001 and 18% for the year ended December 31, 2000. We expect that turnkey and footage contracts will represent approximately 7% to 10% of the total days worked in 2002.

Turnkey and footage contracts generated earnings before interest, income taxes, depreciation and amortization ("EBITDA") of $2.7 million in the fourth quarter of 2001 compared to $5.4 million in the third quarter of 2001. For the years ended December 31, 2001 and 2000, turnkey and footage contracts generated EBITDA of $16.5 million and $9.6 million, respectively. For the fourth quarter of 2001, our turnkey operating margin was $8,717 per rig day, which was 69% greater than the $5,151 daywork margin per rig day.

The revenue and EBITDA generated on turnkey and footage contracts varies widely based upon a number of factors, including the location of the contracted work as well as the depth and level of complexity of the wells drilled. The demand for drilling services under turnkey and footage contracts has historically been greater during periods of overall lower demand. There can be no assurance that we will be able to maintain the current level of revenue or EBITDA derived from turnkey and footage contracts.

New Markets

We began operations in the Rocky Mountain market in June 2001 under a two-year term contract for our ultra-deep drilling Rig 558. In October 2001, we deployed a second rig into the market under a one-year term contract.

In May 2001, we signed a two-year term contract for a 3,000 horsepower rig to drill in West Texas. This rig is being upgraded from inventory and is expected to go to work in the second quarter of 2002. Excluding this rig, we currently have four marketed rigs in this market. One rig began operations in October 2001 on a well to well contract basis. The other three rigs began operations in either January or February 2002. Two of these three rigs are working under existing term contracts and the other rig is working on a well to well contract basis.

The presence of these rigs provide us with established operating bases in these two markets which could provide further expansion opportunities.

Closing of Venezuelan Operations

During the second quarter of 2001, we moved our five Venezuela rigs to the United States, and in the third quarter of 2001 sold three of the five rigs for $1.3 million. We no longer have operations or operating assets in the international markets.

Critical Accounting Policy

We assess the impairment of long-lived assets whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The primary factor that we consider important which could trigger an impairment review would be significant negative industry or economic trends. If a review of the Company's long-lived assets indicated that the carrying value of certain drilling rigs was more than the estimated undiscounted future net cash flows, a write-down of the assets to their estimated fair market value would have to be made. The estimation of undiscounted future net cash flows and fair market value would be based on certain estimates and projections as stipulated in Statement of Financial Accounting Standards Board No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets".

During the year ended December 31, 1998, we recorded a pretax unusual charge of $93.2 million for asset impairment as a result of such a review. As of December 31, 2001, net long-lived assets amounted to $448.7 million.

Financial Results

The year ending December 31, 2001 was the best year in the Company's history. Net income for 2001 was $68.5 million compared with a net loss of $8.5 million for 2000. Revenue for 2001 was $421.5 million compared with $269.3 million for the year 2000. EBITDA for 2001 and 2000 was $174.5 million and $47.9 million, respectively.

As a result of the recent decline in demand, however, our financial results declined in the fourth quarter of 2001. Net income for the fourth quarter of 2001 was $9.0 million compared with net income of $25.4 million for the third quarter of 2001. Revenues for the fourth quarter of 2001 and third quarter of 2001 were $86.3 million and $125.1 million, respectively. EBITDA was $30.6 million for the fourth quarter of 2001 compared with $55.9 million for the third quarter of 2001.

Our operating margin for the quarter ended December 31, 2001 was $5,337 per rig day, down $1,634 per rig day, or 23% from the third quarter 2001 operating margin of $6,971 per rig day. The fourth quarter 2001 daily operating margin was $5,337, which was $2,052 per rig day, or 62% greater than the fourth quarter 2000 operating margin of $3,285 per rig day. Our margin for the years ended December 31, 2001 and 2000 was $5,963 per rig day and $2,150 per rig day, respectively. This represents an improvement of $3,813 per rig day, or 177% year over year.

Financial Outlook and Strategy

Based on currently anticipated levels of activity and dayrates, we expect to generate an operating margin of approximately $3,200 per rig day for the first quarter of 2002. This operating margin level should generate EBITDA of approximately $14.8 million for the quarter and the resultant net loss per share is expected to be approximately $.01 on a diluted basis, assuming an effective tax benefit rate of approximately 25%. We expect depreciation expense of approximately $11.3 million in the first quarter of 2002.

Capital expenditures for all of 2002 are projected to be approximately $22.5 million. Our capital expenditures during 2002 will largely be based upon our number of rigs working. It is our strategy to control capital expenditures while maintaining our equipment. We will continue to reduce costs quickly on rigs added to inventory, but intend to retain our experienced toolpushers and drillers as we did in the last down cycle. The recent up cycle proved there was a tremendous need for experienced personnel and our decision to retain them during the last downturn provided a long-term advantage by allowing us to enter into term contracts. We currently have no plans to cut wages. It is important to note, however, that due to current economic conditions and recent events, the cost of our insurance coverages are expected to escalate at the next renewal dates in mid-2002 and mid-2003. The anticipated increases in the cost of insurance, which are not yet determinable, could have an adverse effect on our financial position and results of operations.

We believe that higher dayrates across our fleet of rigs are more beneficial than maintaining higher utilization by discounting prices. We also believe that customers prefer to make the decision of which contractor to use based upon safety, quality of service, and value added as opposed to price considerations alone. Our strategy remains unchanged and that is to provide the greatest value for our customers in order to obtain the highest rates for our rigs throughout the cycles of our industry.

Financial Condition and Liquidity

The following table summarizes our financial position as of December 31, 2001 and December 31, 2000.

	December 31, 2001		December 31, 2000	
	(In thousands)			
	Amount	%	Amount	%
Working capital	$ 113,163	20	$ 60,029	13
Property and equipment, net	448,660	79	386,861	85
Other noncurrent assets	5,744	1	6,658	2
Total	$ 567,567	100	$ 453,548	100
Long-term debt	$ 250,695	44	$ 249,851	55
Other long-term liabilities	71,575	13	30,281	7
Shareholders' equity	245,297	43	173,416	38
Total	$ 567,567	100	$ 453,548	100

The significant changes in our financial position from December 31, 2000 to December 31, 2001 are the increases in working capital of $53.1 million, net property and equipment of $61.8 million, other long-term liabilities of $41.3 million, and shareholders' equity of $71.9 million. The increase in working capital is primarily due to a $5.8 million increase in accounts receivable and $47.5 million increase in cash which is due to increases in dayrates and drilling activity year over year. The increase in net property and equipment is primarily due to $104.7 million of capital expenditures, $55.5 million of which related to rig upgrades and reactivation offset by $41.4 million in depreciation expense. Other long-term liabilities increased primarily as the result of a higher deferred income tax liability of $38.6 million due to higher earnings. Shareholders' equity increased primarily due to net income of $68.5 million.

Senior Notes

In June 1997 and May 1998, the Company concluded public offerings of $175.0 million and $75.0 million, respectively, in principal amount of the senior notes. The senior notes ("Notes") bear interest at 8⅞% per annum and mature July 1, 2007. The Notes are general unsecured senior obligations of the Company and are fully and unconditionally guaranteed, on a joint and several basis, by all domestic wholly-owned subsidiaries of the Company. In addition, non-guarantor subsidiaries are immaterial.

The Notes are not redeemable at the option of the Company prior to July 1, 2002. On or after such date, the Company will have the option to redeem the Notes in whole or in part during the twelve months beginning July 1, 2002 at 104.4375%, beginning July 1, 2003 at 102.9580%, beginning July 1, 2004 at 101.4792% and beginning July 1, 2005 and thereafter at 100.0000% together with any interest accrued and unpaid to the redemption date. Upon a change of control as defined in the indentures, each holder of the Notes will have the right to require the Company to repurchase all or any part of such holder's Notes at a purchase price equal to 101% of the aggregate principal amount thereof, plus accrued and unpaid interest to the date of purchase.

The indentures for the Notes permit us and our subsidiaries to incur additional indebtedness, including senior indebtedness of up to $100.0 million aggregate principal amount which may be secured by liens on all of our assets and the assets of our subsidiaries, subject to certain limitations. The indentures contain other covenants limiting our ability and our subsidiaries to, among other things, pay dividends or make certain other restricted payments, make certain investments, incur additional indebtedness, permit liens, incur dividend and other payment restrictions affecting subsidiaries, enter into consolidation, merger, conveyance, lease or transfer transactions, make asset sales, enter into transactions with affiliates or engage in unrelated lines of business. These covenants are subject to certain exceptions and qualifications. The indentures consider non-compliance with the limitations events of default. In addition to non-payment of interest and principal amounts, the indentures also consider default with respect to other indebtedness in excess of $10.0 million an event of default. In the event of a default, the principal and interest could be accelerated upon written notice by 25% or more of the holders of our senior notes. We are in compliance with these covenants.

We owe a total of $250.0 million in principal amount under our senior notes. While the principal is not due until 2007, semi-annual interest payments of approximately $11.1 million are due on January 1 and July 1 of each year.

For the year ended December 31, 2001, our operating activities and financing activities provided cash, while our investing activities consumed cash. To the extent we are unable to generate cash flow sufficient to pay debt service and meet our other cash needs, including capital expenditures, we would be required to use our cash on hand. At March 14, 2002, our cash balance was $99.2 million.

CIT Facility

In December 2001, we amended our $50.0 million credit facility with the CIT Group/Business Credit, Inc. (the "CIT Facility") to increase the amount available under the facility to $75.0 million. The term of the CIT Facility was also extended to January 2006 from January 2003. The CIT Facility provides us with the ability to borrow up to the lesser of $75.0 million or 50% of the orderly liquidation value (as defined in the agreement) of certain drilling rig equipment located in the 48 contiguous United States. The CIT Facility is a revolving facility with automatic renewals after expiration unless terminated by the lender on any subsequent anniversary date and then only upon 60 days prior notice. Periodic interest payments are due at a floating rate based upon our debt service coverage ratio within a range of either LIBOR plus 1.75% to 3.5% or prime plus 0.25% to 1.5%. The CIT Facility provides up to $10.0 million available for letters of credit. We are required to pay a commitment fee of 0.375% per annum on the unused portion of the CIT Facility and letters of credit accrue a fee of 1.25% per annum. In addition, the CIT Facility contains certain affirmative and negative covenants and we are in compliance with these covenants. Substantially all of our assets, including its drilling equipment, are pledged as collateral under the CIT Facility and it is also secured by our guarantees and certain of our wholly-owned subsidiaries guarantees. We, however, retain the option, subject to a minimum appraisal value, under the CIT Facility to extract $75.0 million of the equipment out of the collateral pool for other purposes. We currently have no borrowings outstanding under the CIT facility and had $7.4 million outstanding under letters of credit at December 31, 2001. Any outstanding letters of credit reduce the amount available for borrowing under the CIT facility.

Under the CIT facility the lender's commitments will be reduced by the amount of net cash proceeds received by us or our subsidiaries from sales or other dispositions of collateral in excess of $1.0 million individually or $2.0 million in the aggregate in any 12 month period (other than sales or other dispositions of certain types of inventory, rigs identified in the CIT facility as equipment held for sale and up to $75.0 million of rigs and accessories). In addition, mandatory prepayments would be required upon:

- the receipt of net proceeds received by us or our subsidiaries from the incurrence of certain other debt or sales of debt or equity securities in a public offering or private placement, or;
- the receipt of net cash proceeds by us or our subsidiaries from asset sales (including proceeds from sale of rigs identified in the credit agreement as equipment held for sale but excluding proceeds from dispositions of inventory in the ordinary course of business, and sales of up to $75.0 million of rigs and rig accessories, or;
- the receipt of insurance proceeds on our assets in each case to the extent that such proceeds are in excess of $500,000 individually or $1.0 million in the aggregate in any twelve month period.

Among the various covenants that we must satisfy under the CIT facility are the following two covenants which apply whenever our liquidity, defined as the sum of cash, cash equivalents and availability under the CIT facility, falls below $25.0 million.

- 1 to 1 EBITDA coverage of debt service, tested monthly on a trailing 12 month basis; and
- minimum tangible net worth (all as defined in the CIT facility) at the end of each quarter will be at least the prior year tangible net worth less $30.0 million adjusted for quarterly tests.

Additionally, it will be a covenant default if the orderly liquidation value of our domestic drilling equipment (including inventoried rigs) falls below $150.0 million. Also, if the two month average rig utilization rate falls below 45%, the lender will have the option to request one additional appraisal per year to aid in determining the current orderly liquidation value of the drilling equipment. Prepayment would be required if the orderly liquidation value falls below the level specified above.

The CIT facility also contains provisions restricting our ability to, among other things:

- engage in new lines of business unrelated to our current activities;

- enter into mergers or consolidations or asset sales or purchases (with specified exceptions);
- incur liens or debts or make advances, investments or loans (in each case, with specified exceptions);
- pay dividends or redeem stock (except for certain inter-company transfers);
- prepay or materially amend any other indebtedness; and
- issue any stock (other than common stock).

Events of default under the CIT facility include, in addition to non-payment of amounts due, misrepresentations and breach of loan covenants and certain other events of default:

- default with respect to other indebtedness in excess of $350,000;
- judgements in excess of $350,000; or
- a change in control (meaning that we cease to own 100% of our two principal subsidiaries, some person or group has either acquired beneficial ownership of 30% or more of the Company or obtained the power to elect a majority of our board of directors or our board of directors ceases to consist of a majority of "continuing directors" (as defined by the CIT facility).

Certain Contractual Commitments

The following table summarizes our contractual cash obligations and related payments due by period at December 31, 2001 (amounts in thousands):

	Payments Due by Period (1)				
Contractual Obligation	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Senior notes (2)					
Principal	$ 250,000	$ –	$ –	$ –	$ 250,000
Interest	133,124	22,187	66,563	22,187	22,187
Capital lease obligations	1,712	543	976	193	–
Operating leases	1,884	632	1,118	134	–
Total contractual cash obligations	$ 386,720	$ 23,362	$ 68,657	$ 22,514	$ 272,187

(1) Assumes no acceleration of maturity dates due to redemption or to breach of, or default under, the terms of the applicable contractual obligation.

(2) See "Senior Notes", above, for information relating to certain financial ratio covenants and certain other covenants the breach of which could cause a default under, and acceleration of the maturity date of, the Senior Notes.

If we choose to borrow under our $75.0 million CIT Facility, under which no amounts are currently outstanding, or if standby letters of credit which we cause to be issued are drawn upon by the holders of those standby letters of credit, then we will become obligated to repay those amounts along with any accrued interest and fees. The following table sets forth the potential maturities of these obligations assuming we had borrowed the maximum amount currently available under the CIT Facility at December 31, 2001, and illustrates the current outstanding letters of credit at December 31, 2001(amounts in thousands):

	Amount of Commitment Expiration Per Period (1)				
Potential Commercial Commitment	Total Committed	Less than 1 year	1-3 years	4-5 years	Over 5 years
Line of credit (2)	$ 67,593	$ –	$ –	$ 67,593	$ –
Standby letters of credit (3)	7,407	5,426	1,981	–	–
Total commercial commitments	$ 75,000	$ 5,426	$ 1,981	$ 67,593	$ –

(1) Assumes no acceleration of maturity date due to breach of, or default under, the commercial commitment.

(2) See "CIT Facility", above, for information relating to financial covenants and other certain covenants that could cause the maturity date under the CIT Facility to be accelerated. However, we currently have no amounts outstanding. If amounts were outstanding we would have to pay interest on these amounts based upon the terms of the CIT Facility.

(3) The CIT Facility provides up to $10.0 million available for letters of credit at any given time. Amount shown represents current outstanding letters of credit.

Cash Flow

The net cash provided by or used in our operating, investing and financing activities is summarized below (amounts in thousands):

	Years Ended December 31,		
	2001	2000	1999
Net cash provided by (used in):			
Operating activities	$ 148,135	$ 15,812	$ (17,470)
Investing activities	(101,123)	(38,536)	(5,808)
Financing activities	491	53,793	(2,117)
Net increase (decrease) in cash:	$ 47,503	$ 31,069	$ (25,395)

Our cash flows from operating activities are affected by a number of factors including the number of rigs under contract, whether the contracts are daywork, footage, or turnkey, and the rate received for these services. Our cash flow generated from operating activities during the year ended December 31, 2001 was $150.5 million (before changes in operating assets and liabilities) compared to cash generated from operating activities during the year ended December 31, 2000 of $27.2 million (before changes in operating assets and liabilities). This change is principally due to an 18% increase in operating days and a 177% increase in our per rig day operating margins between the two periods. Our cash flows from operating activities were also impacted by changes in operating assets and liabilities which used $2.4 million and $11.3 million in cash flow for the years ended December 31, 2001 and 2000, respectively. Our cash flow generated from operating activities during the year ended December 31, 2000 was $27.2 million (before changes in operating assets and liabilities) compared to cash used in operating activities during the year ended December 31, 1999 of $21.9 million (before changes in operating assets and liabilities). This change is principally due to a 59% increase in operating days and an increase in our per rig day operating margins between the two periods. Our cash flows from operating activities were also impacted by changes in operating assets and liabilities which used $11.3 million and provided $4.4 million in cash flow for the years ended December 31, 2000 and 1999, respectively.

Cash flow used in investing activities for the year ended December 31, 2001 primarily consisted of $103.0 million of capital expenditures for reactivating rigs, drill pipe and collars, top drives, and other capital items. Our cash flow used in investing activities for the year ended December 31, 2000 primarily consisted of $38.7 million of capital expenditures for reactivating rigs, top drives, and other capital items. Cash flow used in investing activities for the year ended December 31, 1999, primarily consisted of capital expenditures on our working rigs.

Cash flow provided by financing activities for the year ended December 31, 2001 consisted principally of $1.7 million from stock option exercises partially offset by $911,000 for repayment of long-term lease obligations. Cash flow provided by financing activities for the year ended December 31, 2000 consisted principally of net proceeds of $51.6 million and $3.2 million from the sale of common stock and from stock option exercises, respectively, partially offset by $1.1 million repayment of long-term lease obligations. Cash flow used in financing activities for the year ended December 31, 1999 primarily consisted of financing costs of $861,000 related to our senior secured revolving credit facility, $1.1 million repayment of long-term lease obligations, and $305,000 for the redemption of all outstanding shares of Series A Preferred Stock.

Results of Operations

The following tables highlight rig days worked, contract drilling revenues and drilling operating expenses for our daywork and turnkey operations for the years ended December 31, 2001, 2000 and 1999.

	For the Year Ended December 31, 2001		
	Daywork Operations	Turnkey Operations (2)	Total
	(Dollars in thousands, except averages per rig day worked)		
Rig days worked	28,766	2,158	30,924
Contract drilling revenue	$ 363,984	$ 57,517	$ 421,501
Drilling operating expenses(1)	196,728	40,362	237,090
Operating margin (loss)	$ 167,256	$ 17,155	$ 184,411
Averages per rig day worked:			
Contract drilling revenue	$ 12,653	$ 26,657	$ 13,630
Drilling operating expenses	6,839	18,707	7,667
Operating margin (loss)	$ 5,814	$ 7,950	$ 5,963

	For the Year Ended December 31, 2000		
	Daywork Operations	Turnkey Operations (2)	Total
	(Dollars in thousands, except averages per rig day worked)		
Rig days worked	21,533	4,574	26,107
Contract drilling revenue	$ 187,408	$ 81,926	$ 269,334
Drilling operating expenses(1)	141,891	71,398	213,289
Operating margin (loss)	$ 45,517	$ 10,528	$ 56,045
Averages per rig day worked:			
Contract drilling revenue	$ 8,703	$ 17,911	$ 10,317
Drilling operating expenses	6,585	15,610	8,167
Operating margin (loss)	$ 2,118	$ 2,301	$ 2,150

	For the Year Ended December 31, 1999		
	Daywork Operations	Turnkey Operations (2)	Total
	(Dollars in thousands, except averages per rig day worked)		
Rig days worked	13,250	3,186	16,436
Contract drilling revenue	$ 89,863	$ 57,340	$ 147,203
Drilling operating expenses(1)	94,706	46,218	140,924
Operating margin (loss)	$ (4,843)	$ 11,122	$ 6,279
Averages per rig day worked:			
Drilling revenue	$ 6,782	$ 17,997	$ 8,956
Operating expenses	7,148	14,507	8,574
Operating margin (loss)	$ (366)	$ 3,490	$ 382

(1) Drilling operating expenses exclude depreciation, general and administrative expenses, and unusual charges.
(2) Turnkey operations include the results from turnkey and footage contracts.

Successfully completed turnkey and footage contracts generally result in higher effective revenues per rig day worked than under daywork contracts. Operating margins per rig day worked on successful turnkey and footage jobs are also generally greater than under daywork contracts, although we are typically required to bear additional operating costs (such as drilling mud costs) that would typically be paid by the customer under daywork contracts. Revenues, operating expenses and gross profit (or loss) margins on turnkey and footage contracts are affected by a number of variables, and include the depth of the well, geological complexities and the actual difficulties encountered in completing the well.

Comparison of Fiscal Years ended December 31, 2001 and 2000

Contract drilling revenue increased approximately $152.2 million, or 56%, to $421.5 million for the year ended December 31, 2001, from $269.3 million for the year ended December 31, 2000. The increase is due to an increase in total rig days worked of 4,817 days, or 18%, and an increase in the total average revenue per rig day of $3,313, or 32%. The increase in the total days worked is the result of a 34% increase in daywork drilling activity partially offset by a 53% decrease in turnkey drilling activity. The increase in the total average revenue per rig day is due to higher dayrates received from both daywork and turnkey operations.

Drilling operating expenses increased by approximately $23.8 million, or 11%, to $237.1 million for the year ended December 31, 2001, as compared to $213.3 million for the year ended December 31, 2000. The increase is the direct result of the overall increased level of activity from daywork operations and increases in wages partially offset by a decreased level of activity from turnkey operations discussed above. Operating expenses on a per rig day basis, however, decreased due to overhead items being spread over more days worked and a decrease in the percentage of turnkey days worked to total days worked from 18% in 2000 to 7% in 2001. The decrease in operating expenses on a per rig day basis was partially offset by wage increases of 5% on July 1, 2000, 14% on August 31, 2000, and 12% on June 1, 2001.

Depreciation expense increased by $4.7 million, or 13%, to $41.4 million for the year ended December 31, 2001 compared to $36.8 million for the year ended December 31, 2000. The increase is primarily due to additional depreciation attributable to capital expenditures during the year ended December 31, 2001.

General and administrative expenses increased by $1.8 million, or 22%, to $9.9 million for the year ended December 31, 2001 compared to $8.1 million for the year ended December 31, 2000, due primarily to the increased level of our operating activity and accrual of performance based compensation.

The difference in interest expense for the years ended December 31, 2001 and 2000 is negligible as the average outstanding debt balance was virtually the same and the largest component of our debt structure is our senior notes which carry interest at a fixed rate.

Interest income decreased by $649,000, or 21%, to $2.4 million for the year ended December 31, 2001, from $3.1 million for the year ended December 31, 2000 due to lower interest rates in 2001 partially offset by higher cash balances. Cash balances were higher as a result of the issuance of 13.0 million shares of common stock on April 4, 2000 and due to higher drilling activity and dayrates in 2001.

Net other expenses increased by $416,000 to $446,000 for the year ended December 31, 2001 from $30,000 for the same period of 2000 due primarily to the realization of $454,000 in previously unrealized foreign currency translation losses as a result of moving our Venezuela rigs to the United States. We no longer have operations or operating assets in the Venezuela market.

Comparison of Fiscal Years ended December 31, 2000 and 1999

Contract drilling revenue increased approximately $122.1 million, or 83%, to $269.3 million for the year ended December 31, 2000, from $147.2 million for the year ended December 31, 1999. The increase is due to an increase in total rig days worked of 9,671 days, or 59%, and an increase in the total average revenue per rig day of $1,361, or 15%. The increase in the total days worked is the result of a 63% increase in daywork drilling activity and a 44% increase in turnkey drilling activity, while the increase in the total average revenue per rig day is due primarily to higher dayrates received from daywork operations.

Drilling operating expenses increased by approximately $72.4 million, or 51%, to $213.3 million for the year ended December 31, 2000, as compared to $140.9 million for the year ended December 31, 1999. The increase is the direct result of the overall increased level of activity from both daywork and turnkey operations discussed above and increases in wages. Operating expenses on a per rig day basis, however, decreased due to overhead items being spread over more days worked and a decrease in the percentage of turnkey days worked to total days worked from 19% in 1999 to 18% in 2000. Increases in crew wages of 5% on July 1, 2000 and 14% on August 31, 2000 offset a portion of the decrease.

Depreciation expense increased by $2.8 million, or 8%, to $36.8 million for the year ended December 31, 2000 compared to $34.0 million for the year ended December 31, 1999. The increase is primarily due to additional depreciation attributable to capital expenditures during the last half of 1999 and during the year ended December 31, 2000.

General and administrative expenses increased by $1.5 million, or 22%, to $8.1 million for the year ended December 31, 2000 compared to $6.7 million for the year ended December 31, 1999, due primarily to the increased level of our operating activity.

During the year ended December 31, 1999, we recorded $320,000 in unusual charges. These unusual charges consisted entirely of severance costs.

The difference in interest expense for the years ended December 31, 2000 and 1999 is negligible as the average outstanding debt balance was virtually the same and the largest component of our debt structure is our senior notes which carry interest at a fixed rate.

Interest income increased by $1.6 million, or 103%, to $3.1 million for the year ended December 31, 2000, from $1.5 million for the year ended December 31, 1999 due primarily to higher cash balances. Cash balances were higher as a result of the issuance of 13.0 million shares of common stock on April 4, 2000 which netted the Company $51.6 million.

During the year ended December 31, 1999 we wrote off $623,000 in deferred loan costs related to our former credit facility. This amount, net of the $203,000 in related taxes, is classified as an extraordinary item.

Inflation and Changing Prices

Contract drilling revenues do not necessarily track the changes in general inflation as they tend to respond to the level of activity of the oil and gas industry in combination with the supply of equipment and the number of competing companies. Capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas industry and to a lesser extent by changes in general inflation.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Interest Rate Risk. We are subject to market risk exposure related to changes in interest rates on our CIT facility. Interest on borrowings under the CIT facility accrues at a variable rate, using (at our election) either the prime rate plus 0.25% to 1.50% or LIBOR plus 1.75% to 3.5%, depending upon our debt service coverage ratio for the trailing 12 month period. On March 14, 2002 we had no outstanding balance under the CIT facility and as such have no exposure at this time to a change in interest rates.

Index to Consolidated Financial Statements and Financial Statement Schedule

Schedules other than those listed above are omitted because they are either not applicable or not required or the information required is included in the consolidated financial statements or notes thereto.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors
of Grey Wolf, Inc.:

We have audited the accompanying consolidated balance sheets of Grey Wolf, Inc. and Subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2001. In connection with our audits of the consolidated financial statements, we have also audited the financial statement schedule for the years ended December 31, 2001, 2000 and 1999. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Grey Wolf, Inc. and Subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects the information set forth therein.

KPMG LLP

Houston, Texas
January 25, 2002

GREY WOLF, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Amounts in thousands, except share data)

	December 31, 2001	December 31, 2000
ASSETS		
Current assets:		
Cash and cash equivalents	$ 99,072	$ 51,569
Restricted cash - insurance deposits	884	859
Accounts receivable, net of allowance of $1,800	67,574	61,729
Prepaids and other current assets	1,942	3,190
Total current assets	169,472	117,347
Property and equipment:		
Land, buildings and improvements	5,137	5,103
Drilling equipment	703,076	606,762
Furniture and fixtures	2,978	2,464
Total property and equipment	711,191	614,329
Less: accumulated depreciation	(262,531)	(227,468)
Net property and equipment	448,660	386,861
Other noncurrent assets	5,744	6,658
	$ 623,876	$ 510,866
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 543	$ 545
Accounts payable - trade	19,770	24,447
Accrued workers' compensation	4,595	4,805
Payroll and related employee costs	7,654	6,795
Accrued interest payable	11,228	11,167
Other accrued liabilities	12,519	9,559
Total current liabilities	56,309	57,318
Senior notes	249,526	249,440
Long-term debt, net of current maturities	1,169	411
Other long-term liabilities	4,868	2,158
Deferred income taxes	66,707	28,123
Commitments and contingent liabilities	–	–
Shareholders' equity:		
Series B Junior Participating Preferred stock, $1 par value; 250,000 shares authorized, none outstanding	–	–
Common stock, $.10 par value; 300,000,000 shares authorized; 180,726,061 and 179,880,591 issued and outstanding, respectively	18,073	17,988
Additional paid-in capital	328,306	325,417
Cumulative translation adjustments	–	(454)
Accumulated deficit	(101,082)	(169,535)
Total shareholders' equity	245,297	173,416
	$ 623,876	$ 510,866

See accompanying notes to consolidated financial statements.

GREY WOLF, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in thousands, except per share data)

	Years Ended December 31,		
	2001	2000	1999
Revenues:			
Contract drilling	$ 421,501	$ 269,334	$ 147,203
Costs and expenses:			
Drilling operations	236,395	213,197	140,347
Depreciation	41,425	36,768	34,003
General and administrative	9,932	8,131	6,678
Provision for doubtful accounts	695	92	577
Unusual charges	–	–	320
Total costs and expenses	288,447	258,188	181,925
Operating income (loss)	133,054	11,146	(34,722)
Other income (expense):			
Interest expense	(24,091)	(23,936)	(24,054)
Interest income	2,441	3,090	1,522
Gain on sale of assets	348	69	556
Other, net	(446)	(30)	(120)
Other income (expense), net	(21,748)	(20,807)	(22,096)
Income (loss) before income taxes	111,306	(9,661)	(56,818)
Income tax expense (benefit)			
Current	2,977	–	–
Deferred	39,876	(1,138)	(15,976)
Total income tax expense (benefit)	42,853	(1,138)	(15,976)
Income (loss) before extraordinary item	68,453	(8,523)	(40,842)
Extraordinary item, net of tax of $203	–	–	(420)
Net income (loss)	$ 68,453	$ (8,523)	$ (41,262)
Basic net income (loss) per common share	$ 0.38	$ (.05)	$ (.25)
Diluted net income (loss) per common share	$ 0.38	$ (.05)	$ (.25)
Basic weighted average common shares outstanding	180,502	175,866	165,108
Diluted weighted average common shares outstanding	182,447	175,866	165,108

See accompanying notes to consolidated financial statements.

GREY WOLF, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(Amounts in thousands)

	Series B Junior Participating Preferred Stock $1 par Value	Common Shares	Common Stock $.10 par Value	Additional Paid-in Capital	Deficit	Cumulative Comprehensive Income Adjustments	Total
Balance, December 31, 1998	–	165,065	$ 16,506	$ 270,389	$(119,750)	$ (454)	$ 166,691
Exercise of stock options	–	102	10	138	–	–	148
Comprehensive net loss	–	–	–	–	(41,262)	–	(41,262)
Balance, December 31, 1999	–	165,167	16,516	270,527	(161,012)	(454)	125,577
Issuance of common stock	–	13,000	1,300	50,334	–	–	51,634
Exercise of stock options	–	1,714	172	3,047	–	–	3,219
Tax benefit of stock option exercises	–	–	–	1,509	–	–	1,509
Comprehensive net loss	–	–	–	–	(8,523)	–	(8,523)
Balance, December 31, 2000	–	179,881	17,988	325,417	(169,535)	(454)	173,416
Exercise of stock options	–	845	85	1,597	–	–	1,682
Tax benefit of stock option exercises	–	–	–	1,292	–	–	1,292
Cumulative foreign translation losses	–	–	–	–	–	454	454
Net income	–	–	–	–	68,453	–	68,453
Comprehensive net income	–	–	–	–	68,453	454	68,907
Balance, December 31, 2001	–	180,726	$ 18,073	$ 328,306	$(101,082)	$ –	$ 245,297

See accompanying notes to consolidated financial statements.

GREY WOLF, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Years Ended December 31,		
	2001	2000	1999
Cash flows from operating activities:			
Net income (loss)	$ 68,453	$ (8,523)	$ (41,262)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation	41,425	36,768	34,003
Provision for doubtful accounts	695	92	577
Extraordinary item, net of taxes	–	–	420
Gain on sale of assets	(348)	(69)	(556)
Foreign exchange loss	446	30	120
Deferred income taxes	38,584	(2,647)	(15,155)
Tax benefit of stock option exercises	1,292	1,509	–
(Increase) decrease in restricted cash	(25)	(97)	–
(Increase) decrease in accounts receivable	(6,540)	(24,819)	(6,788)
(Increase) decrease in other current assets	1,248	(816)	527
Increase (decrease) in accounts payable trade	(4,677)	3,216	7,345
Increase (decrease) in accrued workers' compensation	(210)	1,733	(1,431)
Increase (decrease) in customer advances	(28)	702	–
Increase (decrease) in other current liabilities	3,916	7,638	2,242
Increase (decrease) in other	3,904	1,095	2,488
Cash provided by (used in) operating activities	148,135	15,812	(17,470)
Cash flows from investing activities:			
Property and equipment additions	(102,950)	(38,612)	(6,862)
Proceeds from sales of equipment	1,827	76	1,054
Cash used in investing activities	(101,123)	(38,536)	(5,808)
Cash flows from financing activities:			
Repayments of long-term debt	(911)	(1,060)	(1,099)
Financing costs	(280)	–	(861)
Issuance of common stock	–	51,634	–
Proceeds from exercise of stock options	1,682	3,219	148
Redemption of Series A Preferred stock	–	–	(305)
Cash provided by (used in) financing activities	491	53,793	(2,117)
Net increase (decrease) in cash and cash equivalents	47,503	31,069	(25,395)
Cash and cash equivalents, beginning of year	51,569	20,500	45,895
Cash and cash equivalents, end of year	$ 99,072	$ 51,569	$ 20,500

Supplemental Cash Flow Disclosure

Cash paid for interest:	$ 22,750	$ 22,667	$ 22,625
Cash paid for (refund of) taxes:	$ 3,019	$ –	$ (15)

See accompanying notes to consolidated financial statements.

(1) Summary of Significant Accounting Policies

Nature of Operations. Grey Wolf, Inc. is a Texas corporation formed in 1980. Grey Wolf, Inc. is a holding company with no independent assets or operations but through its subsidiaries is engaged in the business of providing onshore contract drilling services to the oil and gas industry. Grey Wolf, Inc., through its subsidiaries, currently conducts operations in Alabama, Arkansas, Louisiana, Mississippi, Texas and Wyoming and had operations in Venezuela until mid 1999, when international operations were shut down. The consolidated financial statements include the accounts of Grey Wolf, Inc. and its majority-owned subsidiaries (the "Company" or "Grey Wolf"). All significant intercompany accounts and transactions are eliminated in consolidation.

Property and Equipment. Property and equipment is stated at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, between three and fifteen years.

Impairment of Long-Lived Assets and Long-Lived Assets to Be Disposed Of. The Company accounts for long-lived assets in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." This statement requires that long-lived assets and certain identifiable intangibles be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to future net cash flows expected to be generated by an asset. If such assets are considered to be impaired, the impairment to be recognized is measured by an amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

We assess the impairment of long-lived assets whenever events or changes in circumstances indicate that the carrying value may not be recoverable. The primary factor that we consider important which could trigger an impairment review would be significant negative industry or economic trends. If a review of the Company's long-lived assets indicated that the carrying value of certain drilling rigs was more than the estimated undiscounted future net cash flows, a write-down of the assets to their estimated fair market value would have to be made. The estimation of undiscounted future net cash flows and fair market value would be based on certain estimates and projections as stipulated in SFAS No. 121. SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" supercedes SFAS No. 121 for fiscal years beginning after December 15, 2001 but it retains many of the fundamental provisions of that statement.

During the year ended December 31, 1998, we recorded a pretax unusual charge of $93.2 million for asset impairment as a result of such a review. As of December 31, 2001, net long-lived assets amounted to $448.7 million.

Revenue Recognition. Revenue from daywork and footage contracts is recognized based upon the provisions of the contract. Revenue from turnkey drilling contracts is recognized as earned using the percentage-of-completion method based upon costs incurred to date and estimated total contract costs. Provision is made currently for anticipated losses, if any, on uncompleted contracts.

Foreign Currency Translation. Venezuela has a highly inflationary economy as defined by Statement of Financial Accounting Standards No. 52, "Foreign Currency Translation." As such, the Company's functional currency is the U.S. dollar. Accordingly, monetary assets and liabilities denominated in foreign currency are re-measured to U.S. dollars at the rate of exchange in effect at the end of the period. Items of income and expense and other non-monetary amounts are re-measured at historical rates. Gains or losses on foreign currency re-measurement are included in other income (expense), net in the consolidated statement of operations. Prior to 1998, assets and liabilities of foreign subsidiaries were translated into United States dollars at the applicable rate of exchange in effect at the end of the period reported. Revenues and expenses were translated at the applicable weighted average rates of exchange in effect during the period reported. Translation adjustments were reflected as a separate component of shareholders' equity. Any transaction gains and losses were included in net income.

Earnings per Share. Basic earnings per share is based on weighted average shares outstanding without any dilutive effects considered. Diluted earnings per share reflects dilution from all contingently issuable shares, including options, warrants and convertible securities. The following is a reconciliation of basic and diluted weighted average shares outstanding (in thousands):

	2001	2000	1999
Weighted average common shares outstanding - basic	180,502	175,866	165,108
Effect of dilutive securities:			
Options - Treasury Stock Method	1,945	–	–
Weighted average common shares outstanding - diluted	182,447	175,866	165,108

Options to purchase 4.1 million shares for the three months ended December 31, 2001 and September 30, 2001 and 998,500 shares for the three months ended June 30, 2001 and March 31, 2001 were not included in the computation of diluted EPS because the options' exercise price was greater than the average market price of the common shares. The Company incurred net losses for the years ended December 31, 2000, and 1999 and has, therefore, excluded certain securities from the computation of diluted earnings per share as the effect would be anti-dilutive. Securities excluded from the computation of diluted earnings per share for the years ended December 31, 2000 and 1999 were options to purchase 7.3 million shares and 5.7 million shares, respectively.

Income Taxes. The Company records deferred tax liabilities utilizing an asset and liability approach. This method gives consideration to the future tax consequences associated with differences between the financial accounting and tax basis of assets and liabilities. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

The Company and its domestic subsidiaries file a consolidated federal income tax return. The Company's foreign subsidiaries file tax returns in the country where they are domiciled. The Company records current income taxes based on its estimated tax liability in the United States and foreign countries for the period.

Fair Value of Financial Instruments. The carrying amount of the Company's cash and short-term investments approximates fair value because of the short maturity of those instruments. The carrying amount of the Company's credit facility approximates fair value as the interest is indexed to the prime rate or LIBOR. The fair value of the senior notes at December 31, 2001 and 2000 was $245.0 million and $243.8 million, respectively, compared to the carrying value of $250 million. Fair value was estimated based on quoted market prices.

Cash Flow Information. Cash flow statements are prepared using the indirect method. The Company considers all unrestricted highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents.

Restricted Cash. Restricted cash consists of investments in interest bearing certificates of deposit totaling $884,000 at December 31, 2001 and $859,000 at December 31, 2000, as collateral for a letter of credit securing insurance deposits. The carrying value of the investments approximates the current market value.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the use of certain estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

Concentrations of Credit Risk. Substantially all of the Company's contract drilling activities are conducted with major and independent oil and gas companies in the United States. Historically, the Company has not required collateral or other security for the related receivables from such customers. However, the Company has required certain customers to deposit funds in escrow prior to the commencement of drilling. Actions typically taken by the Company in the event of nonpayment include filing a lien on the customer's producing properties and filing suit against the customer.

Comprehensive Income. Comprehensive income includes all changes in a company's equity during the period that result from transactions and other economic events, other than transactions with its stockholders.

Recent Accounting Pronouncements. In June 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standard ("SFAS") No. 142, "Goodwill and Other Intangible Assets," which changes how goodwill and other intangible assets are accounted for subsequent to their initial recognition. Under this standard, goodwill and other intangible assets having identifiable useful lives are no longer amortized, but are subjected to periodic assessments of impairment. SFAS No. 142 is effective for fiscal years beginning after December 15, 2001. The adoption of SFAS 142 will not have a material impact on the Company's financial position or results of operation.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which addressed financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement applies to all entities that have legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of the asset. SFAS 143 is effective for fiscal years beginning after June 15, 2002. The Company does not expect the adoption of SFAS 143 to have a significant impact on its financial condition or results of operations.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Live Assets," which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. While SFAS No. 144 supercedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," it retains many of the fundamental provisions of that statement. SFAS No. 144 also supersedes the accounting and reporting provisions of APB Opinion No. 30, "Reporting the Results of Operations-Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," for the disposal of a segment of a business. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001 and interim periods within those fiscal years. The adoption of SFAS No. 144 will not have a significant impact on the Company's financial condition or results of operations.

(2) Significant Property Transactions

During the second quarter of 2001, the Company moved its five Venezuela rigs to the United States and in the third quarter of 2001 sold three of the five rigs for $1.3 million. This sale resulted in a gain of approximately $602,000. As a result of moving its Venezuela rigs to the United States, the Company realized $454,000 of previously unrealized foreign currency translation losses during the second quarter of 2001.

(3) Income Taxes

The Company and its U.S. subsidiaries file consolidated federal income tax returns. The components of the provision for income taxes consisted of the following (amounts in thousands):

	For the Years Ended December 31,		
	2001	2000	1999
Current			
Federal	$ 1,870	$ –	$ –
State	1,107	–	–
	$ 2,977	$ –	$ –
Deferred			
Federal	$ 38,557	$ (1,366)	$ (15,460)
State	1,319	228	(516)
	$ 39,876	$ (1,138)	$ (15,976)

Deferred income taxes are determined based upon the difference between the carrying amount of assets and liabilities for financial reporting purposes and amounts used for income tax purposes, and net operating loss and tax credit carryforwards. The tax affects of the Company's temporary differences and carryforwards and tax benefits from stock option exercises are as follows (amounts in thousands):

	December 31, 2001	December 31, 2000
Deferred tax assets		
Net operating loss carryforwards	$ 10,549	$ 43,917
Tax credit carryforwards	1,885	14
Workers compensation accruals	3,345	2,711
Other	187	679
	15,966	47,321
Deferred tax liabilities		
Depreciation	82,673	75,444
Net deferred tax liability	$ 66,707	$ 28,123

At December 31, 2001 and 2000, the Company had U.S. net operating loss ("NOL") carryforwards of $51.1 million and $143.7 million, respectively, which expire at various times through 2020. The NOL carryforwards are subject to annual limitations as a result of the changes in ownership of the Company in 1989, 1994 and 1996.

For financial reporting purposes, approximately $21.0 million of the NOL carryforwards was utilized to offset the book versus tax basis differential in the recording of the assets acquired in transactions prior to 1999.

The following summarizes the differences between the federal statutory tax rate of 35% (amounts in thousands):

	For the Years Ended December 31, 2001	2000	1999
Income tax expense (benefit) at statutory rate	$ 38,957	$ (3,381)	$ (19,886)
Increase (decrease) in taxes resulting from:			
Expiration of NOL carryforwards	–	830	2,479
Permanent differences, primarily due to basis differences in acquired assets	1,320	1,226	1,127
Loss of foreign deductions	95	250	426
State taxes (net)	1,576	148	(336)
Other	905	(211)	214
Income tax expense (benefit)	$ 42,853	$ (1,138)	$ (15,976)

(4) Long-Term Debt

Long-term debt consists of the following (amounts in thousands):

	December 31, 2001	December 31, 2000
$250,000 senior notes due 2007, general unsecured senior obligations guaranteed by the Company's domestic subsidiaries, bearing interest at 8⅞% per annum payable semiannually	$ 249,526	$ 249,440
Capital leases, secured by transportation equipment, bearing interest at 10% to 14%	1,712	956
	251,238	250,396
Less current maturities	543	545
Long-term debt	$ 250,695	$ 249,851

In June 1997 and May 1998, the Company concluded public offerings of $175.0 million and $75.0 million, respectively, in principal amount of the senior notes. The senior notes ("Notes") bear interest at 8⅞% per annum and mature July 1, 2007. The Notes are general unsecured senior obligations of the Company and are fully and unconditionally guaranteed, on a joint and several basis, by all domestic wholly-owned subsidiaries of the Company. In addition, non-guarantor subsidiaries are immaterial. All fees and expenses incurred at the time of issuance are being amortized over the life of the Notes.

The Notes are not redeemable at the option of the Company prior to July 1, 2002. On or after such date, the Company shall have the option to redeem the Notes in whole or in part during the twelve months beginning July 1, 2002 at 104.4375%, beginning July 1, 2003 at 102.9580%, beginning July 1, 2004 at 101.4792% and beginning July 1, 2005 and thereafter at 100.0000% together with any interest accrued and unpaid to the redemption date. Upon a change of control as defined in the indentures, each holder of the Notes will have the right to require the Company to repurchase all or any part of such holder's Notes at a purchase price equal to 101% of the aggregate principal amount thereof, plus accrued and unpaid interest to the date of purchase.

In December 2001, we amended our $50.0 million credit facility with the CIT Group/Business Credit, Inc. (the "CIT Facility") to increase the amount available under the facility to $75.0 million. In conjunction with this amendment, we incurred $280,000 in deferred financing costs which will be amortized over the remaining life of the CIT Facility. The term of the CIT Facility was also extended to January 2006 from January 2003. The CIT Facility provides the Company with the ability to borrow up to the lesser of $75.0 million or 50% of the orderly liquidation value (as defined in the agreement) of certain drilling rig equipment located in the 48 contiguous United States. The CIT Facility is a revolving facility with automatic renewals after expiration unless terminated by the lender on any subsequent anniversary date and then only upon 60 days prior notice. Periodic interest payments are due at a floating rate based upon the Company's debt service coverage ratio within a range of either LIBOR plus 1.75% to 3.5% or prime plus 0.25% to 1.5%. The CIT Facility provides up to $10.0 million available for letters of credit. The Company is required to pay a commitment fee of 0.375% per annum on the unused portion of the CIT Facility and letters of credit accrue a fee of 1.25% per annum. In addition, the CIT Facility contains certain affirmative and negative covenants. Substantially all of the Company's assets, including its drilling equipment, are pledged as collateral under the CIT Facility and is also secured by our guarantees and certain of our wholly-owned subsidiaries guarantees. The Company, however, retains the option, subject to a minimum appraisal value, under the CIT Facility to extract $75.0 million of the equipment out of the collateral pool for other purposes. The Company currently has no borrowings outstanding under the CIT facility and had $7.4 million outstanding under letters of credit at December 31, 2001.

In 1999, the Company recognized a non-cash extraordinary loss of $420,000, net of applicable tax benefit of $203,000, related to the write-off of deferred financing costs associated with the Company's previous facility.

The Company had non-cash activities for the years ended December 31, 2001, 2000, and 1999 related to vehicle additions under capital leases. The non-cash amounts excluded from cash used in investing activities and cash provided by financing activities was $1.8 million, $663,000, and $203,000 for the years ended December 31, 2001, 2000, and 1999, respectively.

Annual maturities of the debt outstanding at December 31, 2001 for the next five years are as follows: 2002 - $543,000; 2003 - $513,000; 2004 - $463,000; 2005 - $193,000 ; 2006 $-0- and thereafter $250,000,000.

(5) Capital Stock and Stock Option Plans

On April 4, 2000, the Company completed an offering of 13,000,000 shares of its common stock which yielded net proceeds to the Company of $51.6 million. The shares were purchased by the underwriter for $4.00 per share and the underwriter advised the Company that the shares were resold to the public at a price of $4.125 per share. The proceeds from the issuance of the shares of common stock, net of offering costs have been used to purchase top drive units, for capital expenditures to return some of the Company's rigs to marketed status and for general corporate purposes, including working capital.

On September 21, 1998, the Company adopted a Shareholder Rights Plan (the "Plan") in which rights to purchase shares of Junior Preferred stock will be distributed as a dividend at the rate of one Right for each share of common stock.

Each Right will entitle holders of the Company's common stock to buy one-one thousandth of a share of Grey Wolf's Series B Junior Participating Preferred stock at an exercise price of $11. The Rights will be exercisable only if a person or group acquires beneficial ownership of 15% or more of Grey Wolf's common stock or announces a tender or exchange offer upon consummation of which such person or group would beneficially own 15% or more of Grey Wolf's common stock. Furthermore, if any person becomes the beneficial owner of 15% or more of Grey Wolf's common stock, each Right not owned by such person or related parties will enable its holder to purchase, at the Right's then-current exercise price, shares of common stock of the Company having a value of twice the Right's exercise price. The Company will generally be entitled to redeem the Rights at $.001 per Right at any time until the 10th day following public announcement that a 15% position has been acquired.

The Company's 1982 Stock Option and Long-term Incentive Plan for Key Employees (the "1982 Plan") was canceled in March 1999; however, prior to that date, reserved 2,500,000 shares of the Company's common stock for issuance upon the exercise of options. The Company's 1987 Stock Option Plan for Non-Employee Directors (the "1987 Director Plan") reserved 250,000 shares of common stock for issuance upon the exercise of options and provided for the automatic grant of options to purchase shares of common stock to any non-employee who became a director of the Company. The 1987 Director Plan was canceled in June 1997. The Company's 1996 Employee Stock Option Plan (the "1996 Plan") reserves 10,000,000 shares of the Company's common stock for issuance upon the exercise of options. At December 31, 2001, options under the 1996 Plan to purchase 2,512,065 shares of common stock were available for grant until July 29, 2006. The exercise price of stock options under the 1982 Plan, the 1987 Director Plan and the 1996 Plan approximates the fair market value of the stock at the time the option is granted. The Company has 1,781,750 shares outstanding for other Stock Option Agreements between the Company and its' executive officers and directors. A portion of the outstanding options became exercisable upon issuance and the remaining become exercisable in varying increments over three to five-year periods. The options expire on the tenth anniversary of the date of grant.

On November 13, 2001, the Company amended all outstanding stock option agreements issued under the 1996 Employee Stock Option Plan and certain outstanding stock option agreements issued to executive officers and directors. Based upon the occurrence of certain events ("triggering events"), the amendments provide for accelerated vesting of options and the extension of the period in which a current employee option holder has to exercise his options. The provisions of the amendments provide for accelerated vesting of options after termination of employment of a current option holder within one year of a change of control of the Company (as defined in the amendment). Triggering events that cause an extension of the exercise period, but not longer than the remaining original exercise period, include termination of employment as a result of any reason not defined as termination for cause, voluntary resignation, or retirement in the amendment.

In accordance with Accounting Principles Board Opinion 25 ("APB 25"), the amendments to the stock option agreements create a new measurement date of November 13, 2001. APB 25 requires the Company to determine the intrinsic value of the options at the measurement date and recognize non-cash compensation expense upon the occurrence of a triggering event. The amount of compensation expense that would be recognized upon the occurrence of a triggering event is the difference between the fair market value of the Company's stock on the measurement date and the original exercise prices of the options. As a result of the requirements of APB 25, the Company would have to recognize $7.0 million of compensation expense if a triggering event were to occur for all outstanding options under the amended agreements at December 31, 2001. This amount will decrease for every option that is exercised or cancelled between the measurement date and a triggering event.

Subsequent to December 31, 2001, a triggering event occurred when an officer's employment terminated. As a result, the Company will recognize approximately $515,000 of non-cash compensation expense along with approximately $330,000 of severance cost in the first quarter of 2002.

Stock option activity for all plans was as follows (number of shares in thousands):

	Number of Shares	Option Price Range
Outstanding December 31, 1998	90	$ .69 - $ 1.00
	2,819	$ 1.13 - $ 1.75
	1,543	$ 2.50 - $ 3.69
	1,160	$ 4.06 - $ 4.38
	10	$ 8.25
Granted	2,429	$ .938 - $ 1.50
Exercised	(24)	$ .69 - $ 1.00
	(78)	$ 1.25 - $ 1.50
Canceled	(21)	$ .69 - $ 1.00
	(362)	$ 1.25 - $ 1.50
	(204)	$ 2.56 - $ 3.69
	(193)	$ 4.06
Outstanding December 31, 1999	2,325	$ .69 - $ 1.00
	2,528	$ 1.13 - $ 1.75
	1,340	$ 2.50 - $ 3.69
	966	$ 4.06 - $ 4.38
	10	$ 8.25
Granted	2,031	$ 3.06 - $ 4.50
Exercised	(308)	$ .69 - $ .938
	(690)	$ 1.00 - $ 1.75
	(665)	$ 2.50 - $ 2.88
	(51)	$ 3.13 - $ 4.06
Cancelled	(88)	$ .69 - $ .938
	(70)	$ 3.06 - $ 4.06
	(10)	$ 8.25

Outstanding December 31, 2000	1,928	$ .69	-	$ 1.00
	1,840	$ 1.13	-	$ 1.75
	2,506	$ 2.56	-	$ 3.13
	1,044	$ 4.06	-	$ 4.50
Granted	75	$ 2.41	-	$ 2.72
	1,074	$ 6.32	-	$ 6.37
Exercised	(256)	$ .69	-	$ .938
	(211)	$ 1.13	-	$ 1.63
	(321)	$ 2.56	-	$ 3.06
	(58)			$ 4.06
Cancelled	(6)	$ .938		$ 1.00
	(99)	$ 2.88		$ 4.06
	(4)			$ 6.32
Outstanding December 31, 2001	1,665	$ .69		$ .938
	1,629	$ 1.25		$ 1.75
	2,170	$ 2.41		$ 3.13
	978	$ 4.06		$ 4.50
	1,070	$ 6.32		$ 6.37
Exercisable December 31, 2001	3,157	$ .69		$ 4.50

The Company applies APB Opinion 25 and related interpretations in accounting for its plans. Accordingly, no compensation cost has been recognized. Had compensation cost for the Company's three stock-based compensation plans been determined on the fair value at the grant dates for awards under those plans consistent with the method of SFAS No. 123, the Company's net loss and loss per share would have been adjusted to the pro forma amounts indicated below (amounts in thousands, except per share amounts):

	2001	2000	1999
Net income (loss)			
As reported	$ 68,453	$ (8,523)	$ (41,262)
Pro forma	$ 67,337	$ (9,432)	$ (42,623)
Income (loss) per share - basic and diluted			
As reported	$ .38	$ (.05)	$ (.25)
Pro forma	$ .37	$ (.05)	$ (.26)

For purposes of determining compensation costs using the provisions of SFAS No. 123, the fair value of option grants was determined using the Black-Scholes option-valuation model. The key input variables used in valuing the options were: risk-free interest rate based on the five-year Treasury strips; dividend yield of zero; stock price volatility of 75%; and expected option lives of five years.

(6) Segment Information and Accumulated Comprehensive Income

The Company manages its business as one reportable segment. Although the Company provides contract drilling services in several markets domestically, these operations have been aggregated into one reportable segment based on the similarity of economic characteristics among all markets including the nature of the services provided and the type of customers of such services.

Prior to the third quarter of 2001, the Company managed its business as two reportable segments; domestic operations and foreign operations. Late in the first quarter of 1999, we suspended all operations in Venezuela but retained the option to begin operations at any time. However, during the second quarter of 2001, the Company moved its five Venezuela rigs to the United States and in the third quarter of 2001 sold three of the five rigs for $1.3 million. This sale resulted in a gain of approximately $602,000. As a result of moving the Venezuela rigs to the United States, the Company realized $454,000 of previously unrealized foreign currency translation losses during the second quarter of 2001.

(7) Related-Party Transactions

During 2001, the Company purchased equipment for $119,000 from an affiliate of the Chairman, President and Chief Executive Officer of the Company. The Company also performed contract drilling services for an affiliate of one of the Company's directors. Total revenues recognized from this affiliated Company during 2001 and 2000 were $6.0 million and $2.2 million, respectively.

One of the Company's directors is a partner in a law firm that performed legal services for the Company in 1999. During 1999, the Company paid the firm $41,000.

(8) Lease Commitments

Aggregate minimum lease payments required under noncancellable operating leases having terms greater than one year are as follows as of December 31, 2001: 2002 - $632,000; 2003 - $608,000; 2004 - $510,000; 2005 - $134,000 and 2006 - $0.

Lease payments under operating leases for 2001, 2000, and 1999 were approximately $618,000, $589,000, and $556,000, respectively.

Capital leases for the Company's field trucks and automobiles are included in long-term debt.

(9) Contingencies

The Company is involved in litigation incidental to the conduct of its business, none of which management believes is, individually or in the aggregate, material to the Company's consolidated financial condition or results of operations.

Substantially all of the Company's contract drilling activities are conducted with independent and major oil and gas companies in the United States. Historically, the Company has not required collateral or other security to support the related receivables from such customers. However, the Company has required certain customers to deposit funds in escrow prior to the commencement of drilling. Actions typically taken by the Company in the event of nonpayment include filing a lien on the customer's producing property and filing suit against the customer.

(10) Employee Benefit Plan

The Company has a defined contribution employee benefit plan covering substantially all of its employees. The Company matches 100% of the first 3% of individual employee contributions and 50% of the next 3% of individual employee contributions. Employer matching contributions under the plan totaled $1.3 million, $1.0 million and $771,000 million for the years ended December 31, 2001, 2000 and 1999, respectively. Participants vest in employer matching contributions over a five year period based upon service with the Company.

(11) Unusual Charges

During the year ended December 31, 1999, the Company recorded pre-tax unusual charges of $320,000 which consisted entirely of severance costs for employees terminated during 1999.

(12) Quarterly Financial Data (unaudited)

Summarized quarterly financial data for years ended December 31, 2001, 2000 and 1999 are set forth below (amounts in thousands, except per share amounts).

	Quarter Ended			
	March 2001	June 2001	September 2001	December 2001
Revenues	$ 97,632	$ 112,423	$ 125,119	$ 86,327
Gross Profit [1]	39,624	53,008	58,481	33,993
Operating income	27,534	40,381	45,559	19,580
Income before income taxes	22,270	34,553	40,268	14,215
Net income	13,362	20,732	25,378	8,981
Net income per common share - basic and diluted	.07	.11	.14	.05

	Quarter Ended			
	March 2000	June 2000	September 2000	December 2000
Revenues	$ 58,709	$ 54,937	$ 73,373	$ 82,315
Gross profit (loss) [1]	8,674	8,589	13,693	25,181
Operating income (loss)	(2,069)	(2,376)	2,369	13,222
Income (loss) before income taxes	(7,788)	(7,435)	(2,655)	8,217
Net income (loss)	(5,692)	(5,472)	(2,331)	4,972
Net income (loss) per common share - basic and diluted	(.03)	(.03)	(.01)	.03

	Quarter Ended			
	March 1999	June 1999	September 1999	December 1999
Revenues	$ 37,680	$ 23,748	$ 33,992	$ 51,783
Gross profit (loss) [1]	1,855	(1,210)	891	5,320
Operating loss	(7,902)	(11,478)	(9,650)	(5,692)
Loss before income taxes	(13,458)	(16,901)	(15,087)	(11,372)
Loss before extraordinary item	(9,069)	(12,237)	(11,460)	(8,076)
Net loss	(9,489)	(12,237)	(11,460)	(8,076)
Net loss per common share - basic and diluted	(.06)	(.07)	(.07)	(.05)

(1) Gross profit (loss) is computed as consolidated revenues less operating expenses (which excludes expenses for depreciation, general and administrative, unusual charges, and provision for doubtful accounts).

GREY WOLF, INC. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS
(In thousands)

	Balance at Beginning of Period	Additions Charged to Allowance	Collections and Write-Offs	Balance at End of Period
Year Ended December 31, 1999				
Allowance for doubtful accounts receivable	$ 1,106	$ 577	$ 25	$ 1,708
Year Ended December 31, 2000				
Allowance for doubtful accounts receivable	$ 1,708	$ 92	$ –	$ 1,800
Year Ended December 31, 2001				
Allowance for doubtful accounts receivable	$ 1,800	$ 695	$ (695)	$ 1,800

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item as to our directors and executive officers is hereby incorporated by reference to such information appearing under the captions "Directors" and "Executive Officers" in our definitive proxy statement for our 2002 Annual Meeting of Shareholders and is to be filed with the Securities and Exchange Commission (the "Commission") pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2001.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item as to the compensation of our management is hereby incorporated by reference to such information appearing under the caption "Executive Compensation" in our definitive proxy statement for our 2002 Annual Meeting of Shareholders and is to be filed with the Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2001.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this item as to the ownership by our management and others of our securities is hereby incorporated by reference to such information appearing under the caption "Nominees for Director" and "Ownership by Management and Certain Shareholders" in our definitive proxy statement for our 2002 Annual Meeting of Shareholders and is to be filed with the Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2001.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item as to certain business relationships and transactions with our management and other parties related to us is hereby incorporated by reference to such information appearing under the caption "Certain Transactions" in our definitive proxy statement for our 2002 Annual Meeting of Shareholders and is to be filed with the Commission pursuant to the Securities Exchange Act of 1934 within 120 days of the end of our fiscal year on December 31, 2001.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. and 2. Financial Statements and Schedule

The consolidated financial statements and supplemental schedule of Grey Wolf, Inc. and Subsidiaries are included in Part II, Item 8 and are listed in the Index to Consolidated Financial Statements and Financial Statement Schedule therein.

3. Exhibits

Exhibit No.		Documents
3.1	--	Articles of Incorporation of Grey Wolf, Inc., as amended (incorporated herein by reference to Exhibit 3.1 to Form 10-Q dated May 12, 1999).
3.2	--	By-Laws of Grey Wolf, Inc., as amended (incorporated herein by reference to Exhibit 99.1 to Form 8-K dated March 23, 1999).
4.1	--	Form of Trust Indenture, dated June 27, 1997, relating to the senior notes due 2007 of the Company and Texas Commerce Bank National Association, as Trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Registration Statement on Form S-3 No. 333-26519 filed June 24, 1997).
4.2	--	Supplemental Indenture (to the Trust Indenture dated June 27, 1997), dated as of March 31, 1998, among the Company, the New Guarantor, the Existing Guarantors, and Chase Bank of Texas National Association, as Trustee. (incorporated herein by reference to Exhibit 4.5 to Form 8-K filed May 21, 1998).
4.3	--	Second Supplemental Indenture (to the Trust Indenture dated June 27, 1997), dated as of May 8, 1998, by and among the Company, the Guarantors, and Chase Bank of Texas, National Association, as Trustee (incorporated herein by reference to Exhibit 4.5 to Form 8-K filed May 21, 1998).
*4.4	--	Third Supplemental Indenture (to the Trust Indenture dated June 27, 1997), dated as of January 4, 1999, among the Company, the New Guarantors, the Existing Guarantors, and Chase Bank of Texas, National Association, as Trustee.
4.5	--	Form of Trust Indenture, dated May 8, 1998, relating to the senior notes due 2007 by and among the Company, the Guarantors, and Chase Bank of Texas, National Association, as Trustee (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed May 21, 1998).
*4.6	--	Supplemental Indenture (to the Trust Indenture dated May 8, 1998), dated as of January 4, 1999, among the Company, the New Guarantors, the Existing Guarantors and Chase Bank of Texas, National Association, as Trustee.
4.7	--	Rights Agreement dated as of September 21, 1998 by and between the Company and American Stock Transfer and Trust Company as Rights Agent (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed September 22, 1998).
10.1	--	Indemnification Agreement dated as of March 6, 1997, by and between Grey Wolf Drilling Company and James K.B. Nelson (incorporated herein by reference to Exhibit 10.5 to Form 8-K dated March 10, 1997).
10.2	--	Form of Non-Qualified Stock Option Agreement dated September 3, 1996, by and between the Company and Thomas P. Richards (incorporated herein by reference to Exhibit 10.2 to Registration Statement No. 333-14783).
10.3	--	Form of Incentive Stock Option Agreement dated September 3, 1996, by and between the Company and Ronnie E. McBride (incorporated herein by reference to Exhibit 10.14 to Post Effective Amendment No. 1 to Registration Statement No. 333-14783).
10.4	--	Form of Non-Qualified Stock Option Agreement dated September 3, 1996, by and between the Company and Ronnie E. McBride. (incorporated herein by reference to Exhibit 10.15 to Post Effective Amendment No. 1 to Registration Statement No. 333-14783).

10.5	--	Grey Wolf, Inc. 1996 Employee Stock Option Plan (incorporated herein by reference to Grey Wolf, Inc. 1996 Annual Meeting of Shareholders definitive proxy materials).
10.6	--	Grey Wolf Inc. Amendment to 1996 Employee Stock Option Plan (incorporated herein by reference to Grey Wolf, Inc. 1999 Annual Meeting of Shareholders definitive proxy materials filed April 9, 1999).
10.7	--	Drillers Inc. 1982 Stock Option and Long-Term Incentive Plan for Key Employees (incorporated by reference to Drillers Inc. 1982 Annual Meeting definitive proxy solicitation materials.)
10.8	--	Form of Incentive Stock Option Agreement dated March 17, 1997, by and between the Company and Gary D. Lee (incorporated by reference to DI Industries, inc. Annual Report of Form 10-K for the year ended December 31, 1996.)
10.9	--	Form of Incentive Stock Option Agreement dated February 10, 1998, by and between the Company and David W. Wehlmann (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 1997.)
10.10	--	Revolving Credit Agreement dated as of January 14, 1999 among Grey Wolf Drilling Company LP (as borrower), Grey Wolf, Inc. (as guarantor), The CIT Group/Business Credit, Inc. (as agent) and various financial institutions (as lenders). (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated January 26, 1999.)
*10.11	--	First Amendment to Loan Agreement dated as of December 20, 2001, by and among Grey Wolf Drilling Company, LP (as borrower) and Grey Wolf, Inc. (as guarantor) and the CIT Group/Business Credit, Inc. (as agent) and various financial institutions (as lenders).
10.12	--	Non-Qualified Stock Option Agreement dated January 16, 1999, by and between the Company and Edward S. Jacob, III. (incorporated herein by reference to Grey Wolf, Inc. Annual Report on Form 10-K for the year ended December 31, 1999.)
*10.13	--	Form of Amendment to Non-Qualified Stock Option Agreements dated November 13, 2001, by and between the Company and Thomas P. Richards.
*10.14	--	Form of Amendment to Non-Qualified Stock Option Agreement dated November 13, 2001, by and among the Company (f.k.a. DI Industries, Inc.), Thomas P. Richards and Richards Brothers Interests, L.P.
*10.15	--	Form of Amendment to Non-Qualified Stock Option Agreements dated November 13, 2001, by and between the Company and each of David W. Wehlmann, Edward S. Jacob III, Gary D. Lee, Ronnie E. McBride, Merrie S. Costley, and Donald J. Guedry, Jr.
*10.16	--	Grey Wolf, Inc. Executive Severance Plan effective November 15, 2001.
*10.17	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and Thomas P. Richards.
*10.18	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and David W. Wehlmann.
*10.19	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and Edward S. Jacob III.
*10.20	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and Gary D. Lee.
*10.21	--	Amended and Restated Employment Agreement dated November 13, 2001, by and between the Company and Ronne E. McBride.
*10.22	--	Form of Non-Qualified Stock Option Agreement dated as of February 13, 2002, by and between the Company and each of Frank M. Brown, William T. Donovan, James K.B. Nelson, Robert E. Rose, Steven A. Webster, and William R. Ziegler.
*21.1	--	List of Subsidiaries of Grey Wolf, Inc.
*23.1	--	Consent of KPMG LLP

* Filed herewith

(b) Reports on Form 8-K

None

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, this 15th day of March, 2002

Grey Wolf, Inc.

By: /s/ David W. Wehlmann
David W. Wehlmann, Senior Vice President and
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures and Capacities	Date
By: /s/ Thomas P. Richards Thomas P. Richards, Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 15, 2002
By: /s/ David W. Wehlmann David W. Wehlmann, Senior Vice President and Chief Financial Officer	March 15, 2002
By: /s/ Merrie S. Costley Merrie S. Costley, Vice President and Controller	March 15, 2002
By: /s/ William R. Ziegler William R. Ziegler, Director	March 15, 2002
By: /s/ Frank M. Brown Frank M. Brown, Director	March 15, 2002
By: /s/ William T. Donovan William T. Donovan, Director	March 15, 2002
By: /s/ James K. B. Nelson James K. B. Nelson, Director	March 15, 2002
By: /s/ Robert E. Rose Robert E. Rose, Director	March 15, 2002
By: /s/ Steven A. Webster Steven A. Webster, Director	March 15, 2002

Directors

Frank M. Brown
Retired Senior Vice President ARCO of Alaska
Anchorage, Alaska

William T. Donovan
Principal and Managing Director
Lubar & Company, Inc.
and
Chairman C-2, Inc.
Milwaukee, Wisconsin

James K. B. Nelson
Felicity Ventures, Ltd.
Houston, Texas

Thomas P. Richards
Chairman, President and Chief Executive Officer
Grey Wolf, Inc.
Houston, Texas

Robert E. Rose
Chairman, Global Santa Fe Corporation
Houston, Texas

Steven A. Webster
Chairman, Carrizo Oil & Gas, Inc. and Managing Director of Global Energy Partners
Houston, Texas

William R. Ziegler
Of Counsel to
Satterlee Stephens Burke & Burke LLP
New York, New York

Officers

Thomas P. Richards
President and Chief Executive Officer

Edward S. Jacob, III
Senior Vice President, Operations and Marketing

Gary D. Lee
Senior Vice President, Human Resources

David W. Wehlmann
Senior Vice President and Chief Financial Officer

Merrie S. Costley
Vice President and Controller

Donald J. Guedry, Jr.
Vice President and Treasurer

Subsidary Officers

Forrest M. Conley, Jr.
Vice President, Ark-La-Tex

Dale Love
Vice President, Gulf Coast

James M. Reimers
Vice President, South Texas

J. G. Winters
Vice President, Materials Control

Ronald G. Hale
Vice President

Corporate Headquarters

10370 Richmond Ave., Suite 600
Houston, TX 77042-4136
(713) 435-6100
(713) 435-6170 (fax)
www.gwdrilling.com

Transfer Agent

American Stock Transfer & Trust Company
40 Wall Street
New York, New York 70005
(800) 937-5449

Annual Meeting

Grey Wolf Inc.'s Annual Meeting of Shareholders will be held at 8:30 a.m. on May 14, 2002 at the:
Adam's Mark Hotel
2900 Briarpark Drive
Houston, Texas 77042

Investor Relations

Shareholders are encouraged to contact the Company with questions or requests for information. Additional copies of the Company's Annual Report on Form 10-K as filed with the Securities and Exchange Commission are available without charge upon written request. Inquiries should be directed to:

Investor Relations
Grey Wolf, Inc.
10370 Richmond Ave., Suite 600
Houston, TX 77042-4136
(713) 435-6100
or through our website at
www.gwdrilling.com

Grey Wolf is traded on the American Stock Exchange under the symbol "GW."

This publication includes certain forward-looking statements reflecting the Company's expectations; however, many factors which may affect the actual results, including commodity prices, market and economic conditions, rig supply and demand and industry competition are difficult to predict. Accordingly, these forward-looking statements are subject to a number of risks and uncertainties and actual results and outcomes may differ materially. Please see our Annual Report on Form 10-K for the year ended December 31, 2001, included herein for material factors that could cause actual results to vary.

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