2003 financial

review

Selected Financial Data

{Nabors Industries Ltd. and Subsidiaries}

Operating Data[1][2]

(In thousands, except per share amounts and ratio data)	Year Ended December 31,						Twelve Months Ended December 31, (Unaudited)	Three Months Ended December 31,	Year Ended September 30,		
	2003	2002	2001	2000	1999	1998	1997[3]	1997	1997	1996	1995
Revenues and other income:											
Operating revenues	$ 1,880,003	$ 1,466,443	$ 2,201,736	$ 1,388,660	$ 666,429	$ 1,008,169	$ 1,114,758	$ 302,831	$ 1,028,853	$ 719,604	$ 572,788
Earnings (losses) from unconsolidated affiliates	10,183	14,775	26,334	26,283	3,757	(305)	274	(25)	450	139	–
Interest income	27,752	34,086	53,973	20,581	8,756	1,480	1,936	93	3,422	2,695	1,694
Other income, net	4,908	3,708	28,650	27,157	8,860	31,626	28,502	2,303	40,747	13,690	5,990
Total revenues and other income	1,922,846	1,519,012	2,310,693	1,462,681	687,802	1,040,970	1,145,470	305,202	1,073,472	736,128	580,472
Costs and other deductions:											
Direct costs	1,276,953	973,910	1,366,967	938,651	446,597	663,551	774,856	199,714	737,780	539,665	434,097
General and administrative expenses	165,403	141,895	135,496	106,504	65,288	77,026	72,478	18,580	70,371	56,862	49,094
Depreciation and amortization	226,528	187,665	184,119	148,087	98,152	84,949	72,350	20,313	66,391	46,117	31,042
Depletion	8,599	7,700	5,777	4,326	1,741	–	–	–	–	–	–
Interest expense	70,740	67,068	60,722	35,370	30,395	15,463	16,323	3,979	16,520	11,884	7,611
Total costs and other deductions	1,748,223	1,378,238	1,753,081	1,232,938	642,173	840,989	936,007	242,586	891,062	654,528	521,844
Income before income taxes	174,623	140,774	557,612	229,743	45,629	199,981	209,463	62,616	182,410	81,600	58,628
Income tax (benefit) expense	(17,605)	19,285	200,162	92,387	17,925	74,993	73,443	21,289	67,602	11,100	7,524
Net income	$ 192,228	$ 121,489	$ 357,450	$ 137,356	$ 27,704	$ 124,988	$ 136,020	$ 41,327	$ 114,808	$ 70,500	$ 51,104
Earnings per diluted share	$ 1.25	$ .81	$ 2.24	$ .90	$ .23	$ 1.16	$ 1.24	$ .37	$ 1.08	$ .75	$ .57
Weighted-average number of diluted common shares outstanding	156,897	149,997	168,790	152,417	120,449	112,555	113,793	116,427	111,975	93,752	89,655
Capital expenditures and acquisitions of businesses[4]	$ 357,393	$ 702,843	$ 803,241	$ 334,279	$ 837,732	$ 315,057	$ 381,196	$ 83,814	$ 399,895	$ 177,925	$ 144,560
Interest coverage ratio[5]	6.8 : 1	6.0 : 1	13.3 : 1	11.8 : 1	5.8 : 1	19.4 : 1	18.3 : 1	21.8 : 1	16.1 : 1	11.7 : 1	12.8 : 1

Balance Sheet Data[1][2]

(In thousands, except ratio data)	As of December 31, 2003	2002	2001	2000	1999	1998	As of December 31, (Unaudited) 1997	As of September 30, 1997	1996	1995
Cash and cash equivalents, and short-term and long-term marketable securities	$ 1,532,090	$ 1,330,799	$ 918,637	$ 550,953	$ 111,666	$ 47,340	$ 42,135	$ 53,323	$ 115,866	$ 24,979
Working capital	917,274	618,454	700,816	524,437	195,817	36,822	62,571	70,872	172,091	33,892
Property, plant and equipment, net	2,990,792	2,801,067	2,451,386	1,835,039	1,678,664	1,127,154	923,402	861,393	511,203	393,464
Total assets	5,602,692	5,063,872	4,151,915	3,136,868	2,398,003	1,465,907	1,281,306	1,234,232	871,274	593,272
Long-term debt	1,985,553	1,614,656	1,567,616	854,777	482,600	217,034	226,299	229,507	229,504	51,478
Shareholders' equity	$ 2,490,275	$ 2,158,455	$ 1,857,866	$ 1,806,468	$ 1,470,074	$ 867,469	$ 767,340	$ 727,843	$ 457,822	$ 368,750
Funded debt to capital ratio:										
Gross[6]	0.48 : 1	0.49 : 1	0.46 : 1	0.32 : 1	0.25 : 1	0.26 : 1	0.27 : 1	0.27 : 1	0.35 : 1	0.20 : 1
Net[7]	0.23 : 1	0.26 : 1	0.26 : 1	0.15 : 1	0.20 : 1	0.17 : 1	0.20 : 1	0.20 : 1	0.21 : 1	0.09 : 1

(1) Our acquisitions' results of operations and financial position have been included beginning on the respective dates of acquisition and include Ryan Energy Technologies, Inc. (October 2002), Enserco Energy Service Company Inc. (April 2002), Command Drilling Corporation (November 2001), Pool Energy Services Co. (November 1999), Bayard Drilling Technologies, Inc. (April 1999), New Prospect Drilling Company (May 1998), Can-Tex Drilling & Exploration, Ltd. land rigs (May 1998), Veco Drilling, Inc. land rigs (November 1997), Diamond L Drilling & Production land rigs (November 1997), Cleveland Drilling Company, Inc. (August 1997), Chesley Pruet Drilling Company (April 1997), Adcor-Nicklos Drilling Company (January 1997, retroactive to October 1996), Noble Drilling Corporation land rigs (December 1996), Exeter Drilling Company and its subsidiary, J.W. Gibson Well Services Company (April 1996), and Delta Drilling Company (January 1995). The results of operations also reflect the disposition of our UK North Sea (November 1996) and J.W. Gibson (January 1998) operations.

(2) We changed our fiscal year end from September 30 to December 31, effective for the fiscal year beginning January 1, 1998. The three-month transition period from October 1, 1997 through December 31, 1997 preceded the start of the new fiscal year.

(3) Represents unaudited recast financial data for the twelve months ended December 31, 1997. This data was derived by adjusting the audited results for the year ended September 30, 1997 to exclude the unaudited results for the quarter ended December 31, 1996 and to include the audited results for the three months ended December 31, 1997.

(4) Represents capital expenditures and the portion of the purchase price of acquisitions allocated to fixed assets and goodwill based on their fair market value.

(5) The interest coverage ratio is computed by calculating the sum of income before income taxes, interest expense, depreciation and amortization, and depletion expense and then dividing by interest expense. This ratio is a method for calculating the amount of cash flows available to cover interest expense.

(6) The gross funded debt to capital ratio is calculated by dividing funded debt by funded debt plus capital. Funded debt is defined as the sum of (1) short-term borrowings, (2) current portion of long-term debt and (3) long-term debt. Capital is defined as shareholders' equity.

(7) The net funded debt to capital ratio is calculated by dividing net funded debt by net funded debt plus capital. Net funded debt is defined as the sum of (1) short-term borrowings, (2) current portion of long-term debt and (3) long-term debt and then subtracting cash and cash equivalents and marketable securities. Capital is defined as shareholders' equity.

Management's Discussion and Analysis of Financial Condition and Results of Operations

{Nabors Industries Ltd. and Subsidiaries}

Nature of Operations

Nabors is the largest land drilling contractor in the world, with almost 600 land drilling rigs. We conduct oil, gas and geothermal land drilling operations in the U.S. Lower 48 states, Alaska, Canada, South and Central America, the Middle East, the Far East and Africa. Nabors also is one of the largest land well-servicing and workover contractors in the United States and Canada. We own approximately 750 land workover and well-servicing rigs in the United States, primarily in the southwestern and western United States, and approximately 200 land workover and well-servicing rigs in Canada. Nabors is a leading provider of offshore platform workover and drilling rigs, and owns 45 platform, 16 jack-up and three barge rigs in the Gulf of Mexico and international markets. These rigs provide well-servicing, workover and drilling services. We also have a 50% ownership interest in a joint venture in Saudi Arabia, which owns 17 rigs.

To further supplement and complement our primary business, we offer a wide range of ancillary well-site services, including engineering, transportation, construction, maintenance, well logging, directional drilling, rig instrumentation, data collection and other support services, in selected domestic and international markets. Our land transportation and hauling fleet includes approximately 240 rig and oilfield equipment hauling tractor-trailers and a number of cranes, loaders and light-duty vehicles. We maintain approximately 300 fluid hauling trucks, approximately 800 fluid storage tanks, ten saltwater disposal wells and other auxiliary equipment used in drilling, workover and well-servicing operations in the United States. In addition, we time charter a fleet of 31 marine transportation and supply vessels, which provide transportation of drilling materials, supplies and crews for offshore operations primarily in the Gulf of Mexico. We manufacture and lease or sell top drives for a broad range of drilling applications, directional drilling systems, rig instrumentation and data collection equipment and rig reporting software. We have also made selective investments in oil and gas exploration, development and production activities, most recently with El Paso Corporation.

The majority of our business is conducted through our various Contract Drilling operating segments, which include our drilling, workover and well-servicing operations, on land and offshore. Our operating segments engaged in marine transportation and supply services, drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction and logistics operations are aggregated in a category labeled Other Operating Segments for segment reporting purposes. Our limited oil and gas exploration, development and production operations are included in a category labeled Oil and Gas for segment reporting purposes. A discussion of our results of operations for the last three years is included below. This discussion should be read in conjunction with our accompanying consolidated financial statements and notes thereto.

This discussion includes various forward-looking statements about our markets, demand for our products and services and our future results. These statements are "forward-looking statements" within the meaning of the safe harbor provisions of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Act of 1934. These forward-looking statements are not historical facts, but instead are based upon our analysis of currently available competitive, financial and economic data and our operating plans. They are inherently uncertain and investors should recognize that events and actual results could turn out to be significantly different from our expectations. Important factors, among others, that could cause our results to differ, possibly materially, from those indicated in the forward-looking statements are discussed below under *Forward-Looking Statements*.

As used in this Report, "we," "us," "our" and "Nabors" means Nabors Industries Ltd. and, where the context requires, includes our subsidiaries.

Results of Operations

The following tables set forth certain information with respect to our reportable segments and rig activity:

	Year Ended December 31,			Increase (Decrease)			
(In thousands, except percentages)	2003	2002	2001	2003 to 2002		2002 to 2001	
Reportable segments:							
Operating revenues and Earnings from unconsolidated affiliates:							
Contract Drilling:[1]							
U.S. Lower 48 Land Drilling	$ 476,258	$ 374,659	$ 1,007,300	$ 101,599	27%	$ (632,641)	(63%)
U.S. Land Well-servicing	312,279	294,428	345,785	17,851	6%	(51,357)	(15%)
U.S. Offshore	101,566	105,717	226,078	(4,151)	(4%)	(120,361)	(53%)
Alaska	112,092	118,199	133,634	(6,107)	(5%)	(15,435)	(12%)
Canada	322,303	141,497	86,310	180,806	128%	55,187	64%
International	396,884	320,160	282,404	76,724	24%	37,756	13%
Subtotal Contract Drilling[2]	1,721,382	1,354,660	2,081,511	366,722	27%	(726,851)	(35%)
Oil and Gas[3]	16,919	7,223	5,529	9,696	134%	1,694	31%
Other Operating Segments[4][5]	201,660	174,775	259,298	26,885	15%	(84,523)	(33%)
Other reconciling items[6]	(49,775)	(55,440)	(118,268)	5,665	10%	62,828	53%
Total	$ 1,890,186	$ 1,481,218	$ 2,228,070	$ 408,968	28%	$ (746,852)	(34%)
Adjusted income (loss) derived from operating activities:[7]							
Contract Drilling:							
U.S. Lower 48 Land Drilling	$ 16,800	$ 23,415	$ 286,856	$ (6,615)	(28%)	$ (263,441)	(92%)
U.S. Land Well-servicing	47,082	38,631	64,446	8,451	22%	(25,815)	(40%)
U.S. Offshore	1,649	(1,397)	29,874	3,046	218%	(31,271)	(105%)
Alaska	37,847	31,387	30,445	6,460	21%	942	3%
Canada	59,856	17,413	30,971	42,443	244%	(13,558)	(44%)
International	77,964	76,121	58,549	1,843	2%	17,572	30%
Subtotal Contract Drilling	241,198	185,570	501,141	55,628	30%	(315,571)	(63%)
Oil and Gas	5,850	(1,058)	(737)	6,908	653%	(321)	(44%)
Other Operating Segments	3,266	24,660	87,847	(21,394)	(87%)	(63,187)	(72%)
Other reconciling items[8]	(37,611)	(39,124)	(52,540)	1,513	4%	13,416	26%
Total adjusted income derived from operating activities	$ 212,703	$ 170,048	$ 535,711	$ 42,655	25%	$ (365,663)	(68%)
Interest expense	(70,740)	(67,068)	(60,722)	(3,672)	(5%)	(6,346)	(10%)
Interest income	27,752	34,086	53,973	(6,334)	(19%)	(19,887)	(37%)
Other income, net	4,908	3,708	28,650	1,200	32%	(24,942)	(87%)
Income before income taxes	$ 174,623	$ 140,774	$ 557,612	$ 33,849	24%	$ (416,838)	(75%)

(In thousands, except percentages and rig activity)	Year Ended December 31, 2003	2002	2001	Increase (Decrease) 2003 to 2002		2002 to 2001	
Rig activity:							
Rig years:[9]							
U.S. Lower 48 Land Drilling	143.1	103.0	209.7	40.1	39%	(106.7)	(51%)
U.S. Offshore	14.1	14.5	28.8	(.4)	(3%)	(14.3)	(50%)
Alaska	7.9	9.3	10.9	(1.4)	(15%)	(1.6)	(15%)
Canada	42.1	22.9	20.4	19.2	84%	2.5	12%
International[10]	61.1	55.1	54.5	6.0	11%	.6	1%
Total rig years	268.3	204.8	324.3	63.5	31%	(119.5)	(37%)
Rig hours:[11]							
U.S. Land Well-servicing	1,088,511	1,014,657	1,170,104	73,854	7%	(155,447)	(13%)
Canada Well-servicing[12]	321,472	164,785	–	156,687	95%	164,785	–
Total rig hours	1,409,983	1,179,442	1,170,104	230,541	20%	9,338	1%

(1) These segments include our drilling, workover and well-servicing operations, on land and offshore.

(2) Includes Earnings from unconsolidated affiliates, accounted for by the equity method, of $2.8 million, $3.9 million and $9.0 million for the years ended December 31, 2003, 2002 and 2001, respectively.

(3) Represents our oil and gas exploration, development and production operations.

(4) Includes our marine transportation and supply services, drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction and logistics operations.

(5) Includes Earnings from unconsolidated affiliates, accounted for by the equity method, of $7.4 million, $10.9 million and $17.3 million for the years ended December 31, 2003, 2002 and 2001, respectively.

(6) Represents the elimination of inter-segment transactions.

(7) Adjusted income (loss) derived from operating activities is computed by: subtracting direct costs, general and administrative expenses, and depreciation and amortization, and depletion expense from Operating revenues and then adding Earnings from unconsolidated affiliates. Such amounts should not be used as a substitute to those amounts reported under accounting principles generally accepted in the United States of America (GAAP). However, management evaluates the performance of our business units and the consolidated company based on several criteria, including adjusted income (loss) derived from operating activities, because it believes that this financial measure is an accurate reflection of the ongoing profitability of our company. A reconciliation of this non-GAAP measure to income before income taxes, which is a GAAP measure, is provided within the table set forth immediately following the heading *Results of Operations* above.

(8) Represents the elimination of inter-segment transactions and unallocated corporate expenses.

(9) Excludes well-servicing rigs, which are measured in rig hours. Includes our equivalent percentage ownership of rigs owned by unconsolidated affiliates. Rig years represents a measure of the number of equivalent rigs operating during a given period. For example, one rig operating 182.5 days during a 365-day period represents 0.5 rig years.

(10) International rig years include our equivalent percentage ownership of rigs owned by unconsolidated affiliates which totaled 3.8 years, 3.7 years and 2.3 years during the years ended December 31, 2003, 2002 and 2001, respectively.

(11) Rig hours represents the number of hours that our well-servicing rig fleet operated during the year.

(12) The Canada Well-servicing operation was acquired during April 2002 as part of our acquisition of Enserco Energy Service Company Inc.

2003 Compared to 2002

Operating revenues and Earnings from unconsolidated affiliates for 2003 totaled $1.9 billion, representing an increase of $409.0 million, or 28%, compared to 2002. Adjusted income derived from operating activities and net income for 2003 totaled $212.7 million and $192.2 million ($1.25 per diluted share), respectively, representing increases of 25% and 58%, respectively, compared to 2002.

The increase in our Operating revenues and Earnings from unconsolidated affiliates during 2003 primarily resulted from higher revenues realized by our Canadian, U.S. Lower 48 Land Drilling and International operations. The improved revenues from our Canadian operations resulted from an increase in the level of activity for our land drilling and well-servicing operations driven by increased demand for our services in that market during 2003 and our acquisition of Enserco Energy Service Company Inc. in April 2002. The Enserco acquisition increased the number of drilling rigs owned and operated by Nabors in Canada by 30 drilling rigs while also adding over 200 well-servicing rigs. The improved revenues for our U.S. Lower 48 Land Drilling operations resulted from higher activity levels driven by a gradual increase in demand for drilling services in that market during 2003. The overall increase in demand in these markets was driven by higher average price levels for natural gas in 2003 compared to 2002. International revenues improved primarily as a result of six new long-term contracts for our operation in Mexico.

The increase in adjusted income derived from operating activities during 2003 primarily resulted from the increase in revenues discussed above. However, the overall increase in adjusted income derived from operating activities for 2003 was partially offset by lower average dayrates in our U.S. Lower 48 Land Drilling operations during 2003 and lower margins realized by certain of our Other Operating Segments. The decrease in average dayrates for our U.S. Lower 48 Land Drilling operations resulted from dayrates declining during 2002 and remaining flat until the latter part of 2003, when dayrates began to rise. The decline in dayrates during 2002 resulted from the weakness in this market over the period beginning in the third quarter of 2001 and extending through the end of 2002. The decrease in margins for our Other Operating Segments is discussed in detail below.

Natural gas prices are the primary driver of our U.S. Lower 48 Land Drilling, Canadian and U.S. Offshore (Gulf of Mexico) operations, while oil prices are the primary driver of our Alaskan, International and U.S. Land Well-servicing operations. The Henry Hub natural gas spot price (per Bloomberg) averaged $5.49 per million cubic feet (mcf) during 2003, up from a $3.37 per mcf average during 2002. West Texas intermediate spot oil prices (per Bloomberg) averaged $31.06 per barrel during 2003, up from a $26.17 per barrel average during 2002.

Our operating results for 2004 are expected to increase from levels realized during 2003 given our current expectations of commodity prices and the related impact on drilling and well-servicing activity during 2004. The expected increase in drilling activity is expected to have the largest impact on our Canadian and U.S. Lower 48 Land Drilling operations. Canadian drilling activity is subject to substantial levels of seasonality, as activity levels typically peak in the first quarter, decline substantially in the second quarter, and then generally increase over the last half of the year. As a result of our acquisitions in Canada during 2001 and 2002, this seasonality has a more significant impact on our overall results as our Canadian operations represent a larger portion of our overall operations. We also expect an improvement in operating results for our U.S. Offshore (Gulf of Mexico) operations during 2004 primarily as a result of incremental revenues from three new platform rigs for deepwater development projects that we expect to commence operations during the first half of 2004, as well as a recovery in the level of overall activity in this market. We expect results from our International operations for 2004 to increase slightly as a result of a full year of operations for contracts in India and Indonesia, which began in the last half of 2003, and a full year of operations in Mexico where rigs commenced operations over the first three quarters of 2003. We also expect to see a number of rigs that had been operating under long-term contracts for our International operations that were unexpectedly idled in late 2003, return to work during 2004. Our U.S. Land Well-servicing operations are expected to maintain a steady to slightly upward trend for 2004 given our current expectations of commodity prices during 2004 as discussed above. We expect results from our operations in Alaska to be reduced overall during 2004 compared to 2003, as two of our rigs are nearing completion on contracts that have not yet been renewed or replaced.

Contract Drilling Our Contract Drilling operating segments contain one or more of the following operations: drilling, workover and well-servicing, on land and offshore. Operating revenues and Earnings from unconsolidated affiliates for our Contract Drilling operating segments totaled $1.7 billion and adjusted income derived from operating activities totaled $241.2 million in 2003, representing increases of 27% and 30%, respectively, compared to 2002. Rig years (excluding well-servicing rigs) increased to 268.3 years during 2003 from 204.8 years during 2002 as a result of increased capital spending by our customers, which resulted from the improvement in commodity prices.

U.S. Lower 48 Land Drilling Operating revenues and adjusted income derived from operating activities totaled $476.3 million and $16.8 million, respectively, in 2003, representing an increase of 27% and a decrease of 28%, respectively, compared to 2002. The increase in Operating revenues resulted from the increase in drilling activity driven by higher natural gas prices, which is reflected in the increase in rig years to 143.1 years during 2003 compared to 103.0 years during 2002. Adjusted income derived from operating activities decreased during 2003, despite the increase in rig activity, as a result of lower average dayrates, rising labor costs and higher depreciation expense.

U.S. Land Well-servicing Operating revenues and adjusted income derived from operating activities totaled $312.3 million and $47.1 million, respectively, in 2003, representing increases of 6% and 22%, respectively, compared to 2002. The improved results in 2003 resulted from an increase in well-servicing utilization driven by the increase in spending by our customers during 2003 and a marginal increase in average dayrates compared to 2002. The strengthening in this market resulted primarily from the improvement in commodity prices in 2003. U.S. Land Well-servicing hours increased to 1,088,511 hours during 2003 from 1,014,657 hours during 2002.

U.S. Offshore Operating revenues and adjusted income derived from operating activities totaled $101.6 million and $1.6 million, respectively, in 2003, representing a decrease of 4% and an increase of 218%, respectively, compared to 2002. The decrease in Operating revenues in 2003 primarily relates to the inclusion in our 2002 Operating revenues of $6.4 million of business interruption insurance proceeds related to our Dolphin 105 jack-up rig, which was lost in a hurricane during 2002, and from lower rig years in 2003 compared to 2002. Rig years for our U.S. Offshore operations totaled 14.1 years during 2003 compared to 14.5 years during 2002. The decrease in Operating revenues in 2003 was partially offset by higher average dayrates in 2003 compared to 2002 resulting from an overall tightening of rig supply in the U.S. Gulf of Mexico during 2003. The increase in adjusted income derived from operating activities during 2003 resulted primarily from increased working days for our 1,000-horsepower workover rigs that currently generate higher daily cash margins than the remainder of our rigs, which was only partially offset by lower rig years in 2003. Adjusted income derived from operating activities for 2003 was also positively impacted by lower costs due to increased monitoring of costs on working rigs and reductions in fixed overhead and costs for non-working rigs.

Alaskan Operating revenues and adjusted income derived from operating activities totaled $112.1 million and $37.8 million, respectively, in 2003, representing a decrease of 5% and an increase of 21%, respectively, compared to 2002. The decrease in Operating revenues resulted from lower drilling activity reflected in the decrease in rig years to 7.9 years during 2003 from 9.3 years during 2002, which was primarily driven by our customers decreasing their level of winter exploration activity. This reduced activity level was partially offset by an incremental $5.7 million of Operating revenues, representing business interruption insurance proceeds recorded during 2003 related to the damage incurred on one of our land drilling rigs in 2001, which exceeded the $3.1 million in business interruption insurance proceeds recorded during 2002 related to another rig damaged in 2001. The increase in adjusted income derived from operating activities resulted from the higher level of business interruption insurance proceeds recognized in 2003 versus 2002 and from projects where we earned a standby without crew rate, which adds to revenues at a level lower than standard rates, but with minimal costs of operation.

Canadian Operating revenues and adjusted income derived from operating activities totaled $322.3 million and $59.9 million, respectively, in 2003, representing increases of 128% and 244%, respectively, compared to 2002. These increases reflect an increase in drilling and well-servicing revenues, which resulted from an overall increase in Canadian drilling and well-servicing activity driven by increased commodity prices, and from our acquisition of Enserco in April 2002. Rig years in Canada increased to 42.1 years during 2003 from 22.9 years during 2002. Canadian Well-servicing hours totaled 321,472 hours during 2003 compared to 164,785 hours during the period from April 26, 2002, the date we acquired Enserco, through December 31, 2002.

International Operating revenues and Earnings from unconsolidated affiliates, and adjusted income derived from operating activities totaled $396.9 million and $78.0 million, respectively, in 2003, representing increases of 24% and 2%, respectively, compared to 2002. The improved results in 2003 primarily resulted from six new long-term contracts for our operation in Mexico. International rig years increased to 61.1 years during the current year from 55.1 years during 2002 primarily as a result of these new contracts.

Oil and Gas This operating segment represents our investment in net profits interests of oil and gas exploration, development and production operations. Oil and Gas Operating revenues and adjusted income derived from operating activities totaled $16.9 million and $5.9 million, respectively, in 2003, representing increases of 134% and 653%, respectively, compared to 2002, resulting from the agreements executed with El Paso Corporation in October 2003 discussed below.

On October 8, 2003, we entered into two separate agreements with wholly-owned subsidiaries of El Paso Corporation under which a subsidiary of Nabors will contribute 20% of an estimated $400 million total cost to develop approximately 110 wells in exchange for a 20% net profits interest in such wells (cash proceeds available from production after royalties and operating costs have been paid). The wells included in these agreements include a combination of proved undeveloped, probable and possible reserves located primarily in South Texas, North Louisiana and Offshore Gulf of Mexico. In the event that cash proceeds totaling 117.5% of our total investment are received from the wells subject to the applicable agreement, our net profits interest in those wells will convert to an overriding royalty interest of 0.4% in the wells for the remainder of the wells' productive lives. Either party may terminate the agreements upon 30 days notice. El Paso will serve as operator of all the wells covered in this development program.

On November 6, 2003, we entered into two additional agreements with El Paso to drill up to a total of 12 exploratory wells in South Texas and South Louisiana. Through these agreements and a subsequent election under one of the agreements, we have committed to contribute 25% of El Paso's share of the cost of drilling and completing eight of the wells; 25% of El Paso's share of the cost of drilling to casing point for three of the wells; and 20% of El Paso's share of the cost of drilling to casing point for one of the wells. We are also committed to contribute 12.5% of El Paso's share of any other costs of the exploratory wells and of all costs of any development wells in which we elect to participate on those prospects. In exchange, we receive a 12.5% interest in El Paso's share in the prospect leases where the exploratory wells are drilled, subject to certain penalty deductions in the event we elect to participate in less than all development wells drilled. As of December 31, 2003, three wells had commenced drilling under these agreements with one being declared a dry hole, which resulted in a charge to direct costs of $1.4 million recorded during the fourth quarter of 2003. The other two wells are in various stages of completion, and an independent third party has concluded that those wells are capable of production in paying quantities.

Other Operating Segments These operations include our marine transportation and supply services, drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction and logistics operations. Operating revenues and Earnings from unconsolidated affiliates for our Other Operating Segments totaled $201.7 million during 2003 representing an increase of 15% compared to 2002. This increase primarily resulted from the acquisition of Ryan Energy Technologies, Inc. during the fourth quarter of 2002. Adjusted income derived from operating activities for our Other Operating Segments totaled $3.3 million during 2003 representing a decrease of 87% compared to 2002. While Ryan's results have been additive to our revenues, this new business realized a loss during 2003. In addition, decreased margins from our marine transportation services, which resulted from lower average dayrates, and from our top drive manufacturing operations, which resulted from fewer top drive sales in 2003 compared to 2002, resulted in lower profitability for our Other Operating Segments compared to 2002.

Other Financial Information General and administrative expenses increased by $23.5 million, or 17%, in 2003 compared to 2002 primarily as a result of increases related to our Canadian acquisitions in 2002 and increased International activity. As a percentage of operating revenues, general and administrative expenses decreased in 2003 compared to 2002 (8.8% vs. 9.7%) as these expenses were spread over a larger revenue base.

Depreciation and amortization, and depletion expense increased by $39.8 million, or 20%, in 2003 compared to 2002 as a result of an increase in average rig years for our Canadian land drilling, U.S. Lower 48 Land Drilling and International operations, a full year of depreciation in 2003 on assets acquired in our Enserco (April 2002) and Ryan (October 2002) acquisitions, as well as other capital expenditures during 2002 and 2003.

Interest expense increased by $3.7 million, or 5%, in 2003 compared to 2002 resulting from the issuance of our $225 million aggregate principal amount of 4.875% senior notes and our $275 million aggregate principal amount of 5.375% senior notes in August 2002, which was only partially offset by reduced interest costs realized in 2003 from the issuance of our $700 million zero coupon senior exchangeable notes in June 2003. Such notes will not accrue interest unless we become obligated to pay contingent interest. The proceeds from this debt issuance were used to redeem our $825 million zero coupon convertible senior debentures, which had an effective interest rate of 2.5%. We also redeemed our 8.625% senior subordinated notes due April 2008 on April 1, 2003.

Interest income decreased by $6.3 million, or 19%, in 2003 compared to 2002, reflecting lower average yields on investments resulting from the overall declining interest rate environment, partially offset by higher average cash and marketable securities balances.

Other income increased by $1.2 million, or 32%, in 2003 compared to 2002. Other income for 2003 includes net gains on marketable securities of approximately $6.1 million and net gains on long-term assets of approximately $2.5 million, partially offset by the recognition of approximately $1.2 million of expense in 2003 related to the settlement of amounts due to the counterparty for our range cap and floor derivative instrument, and a loss of approximately $.9 million resulting from the redemption of our 8.625% senior subordinated notes at prices higher than their carrying value on April 1, 2003. Other income for 2002 includes net gains on marketable securities of approximately $2.9 million and net gains on long-term assets of approximately $4.6 million, partially offset by mark-to-market losses recorded on our range cap and floor derivative instrument of approximately $2.0 million and the recognition of approximately $3.8 million in non-recurring corporate reorganization expense.

Our effective income (benefit) tax rate was (10%) during 2003 compared to 14% during 2002. The tax benefit position for 2003 resulted primarily from tax savings realized as a result of our corporate reorganization effective June 24, 2002. It is possible that the tax savings recorded as a result of the corporate reorganization may not be realized, depending on the final disposition of various legislative proposals introduced in the U.S. Congress, and any responsive action taken by Nabors. We expect our effective income tax rate during 2004 to be in the 10%–15% range because we expect a higher proportion of our income to be generated in the U.S., which is generally taxed at a higher rate than in international jurisdictions in which we operate.

2002 Compared to 2001

Operating revenues and Earnings from unconsolidated affiliates in 2002 totaled $1.5 billion, representing a decrease of $746.9 million, or 34%, compared to 2001. Adjusted income derived from operating activities and net income in 2002 totaled $170.0 million and $121.5 million ($.81 per diluted share), respectively, representing decreases of 68% and 66%, respectively, compared to 2001.

The decrease in our operating results in 2002 primarily resulted from the continuing weak environment in several of our key North American markets. The depressed price for natural gas and oil over the period beginning in the third quarter of 2001 through the latter part of the first quarter of 2002 resulted in decreased spending by our customers for our services during the second half of 2001 and for all of 2002.

This decreased spending and corresponding decline in our rig activity resulted in declining profitability for Nabors over that period. These lower activity levels were experienced by a majority of our North American business units, with the sharpest decline coming from our U.S. Lower 48 Land Drilling business. The decrease in North American land and offshore drilling activity is illustrated by the drilling industry's lower total active land and offshore rig count. The drilling industry's average U.S. Land, Canadian Land and U.S. Offshore rig counts during 2002 were lower by 29%, 23% and 26%, respectively, than the 2001 period. Also contributing to the overall decline in our operating results was a decline in activity for our U.S. Land Well-servicing and workover business, driven primarily by lower rig utilization due to the overall weak market, a decline in activity for our operations in Alaska, primarily resulting from lower overall drilling activity in that market, and the loss of some higher margin workover rigs and an offshore platform operation during the second half of 2002.

As discussed above, natural gas prices are the primary driver of our U.S. Lower 48 Land Drilling, Canadian and U.S. Offshore (Gulf of Mexico) operations, while oil prices are the primary driver of our Alaskan, International and U.S. Land Well-servicing operations. The Henry Hub natural gas spot price (per Bloomberg) averaged $3.37 per mcf during 2002, down from the $3.96 per mcf average during 2001. West Texas intermediate spot oil prices (per Bloomberg) averaged $26.17 per barrel during 2002, up slightly from $25.96 per barrel during 2001. Beginning in the first quarter of 2002, a tightening in natural gas and oil supply resulted in an improvement in natural gas and oil prices. Natural gas and oil prices averaged $3.76 per mcf and $28.29 per barrel, respectively, during the last six months of 2002, as compared to $2.98 per mcf and $24.01 per barrel for the first six months of 2002. A substantial portion of the improvement in natural gas prices occurred during the fourth quarter of 2002, when natural gas prices averaged $4.31 per mcf. These price increases did not result in a corresponding strengthening of our key North American markets until early 2003.

Contract Drilling Operating revenues and Earnings from unconsolidated affiliates for our Contract Drilling operating segments totaled $1.4 billion and adjusted income derived from operating activities totaled $185.6 million in 2002, representing decreases of 35% and 63%, respectively, compared to 2001. Rig years (excluding well-servicing rigs) decreased to 204.8 years during 2002 from an average of 324.3 years during 2001. The lower revenues realized by our U.S. Lower 48 Land Drilling, U.S. Land Well-servicing, U.S. Offshore and Alaskan business units during 2002 compared to 2001 were only partially offset by higher revenues from our Canadian and International operations.

U.S. Lower 48 Land Drilling Operating revenues and adjusted income derived from operating activities totaled $374.7 million and $23.4 million, respectively, representing decreases of 63% and 92%, respectively, compared to 2001. These substantial decreases were a result of decreased demand for our drilling services. The weakness of the North American natural gas market during 2002 resulted in significant decreases in both rig years and dayrates. We began to experience this deterioration in North American gas rig activity during the third quarter of 2001 and such reduced rig activity continued through the end of 2002. U.S. Lower 48 Land Drilling rig years decreased to 103.0 years during 2002 from 209.7 years during 2001.

U.S. Land Well-servicing Operating revenues and adjusted income derived from operating activities totaled $294.4 million and $38.6 million, respectively, in 2002, representing decreases of 15% and 40%, respectively, compared to 2001. These decreases resulted from decreased activity as a function of the reduction in capital spending by our customers resulting from lower oil prices in the beginning of 2002 and, to a lesser extent, lower natural gas prices over the same period. U.S. Land Well-servicing rig hours decreased to 1,014,657 hours during 2002 from 1,170,104 hours during 2001.

U.S. Offshore Operating revenues and adjusted income (loss) derived from operating activities totaled $105.7 million and ($1.4 million), respectively, in 2002, representing decreases of 53% and 105%, respectively, compared to 2001. These decreases resulted from lower rig years and lower average dayrates. This negative trend began during the third quarter of 2001 and continued through the second quarter of 2002, following the similar decline in natural gas and oil prices over that period. During that period of time offshore operators reduced their demand for offshore rigs and the prices they were willing to pay for offshore services in the Gulf of Mexico. Offshore rig years decreased to 14.5 years during 2002 from 28.8 years during 2001. Our U.S. Offshore unit's 2002 operating results include an incremental $6.4 million, representing business interruption insurance proceeds related to our Dolphin 105 jack-up rig, which was lost in a hurricane during 2002. We also recorded a $2.3 million gain as a result of a casualty insurance settlement in excess of the carrying value of this rig, which is included in other income in our consolidated statement of income for the year ended December 31, 2002.

Alaskan Operating revenues and adjusted income derived from operating activities totaled $118.2 million and $31.4 million, respectively, in 2002, representing a decrease of 12% and an increase of 3%, respectively, compared to 2001. The decrease in Operating revenues resulted from lower drilling activity reflected in the decrease in rig years to 9.3 years during 2002 from 10.9 years during 2001. This reduced activity level was partially offset by an incremental $3.1 million in Operating revenues, representing business interruption insurance proceeds recorded during 2002 related to damage incurred on one of our land drilling rigs in 2001, which resulted in the small increase in adjusted income derived from operating activities in 2002 compared to 2001.

Canadian Operating revenues and adjusted income derived from operating activities totaled $141.5 million and $17.4 million, respectively, in 2002, representing an increase of 64% and a decrease of 44%, respectively, compared to 2001. The increase in Operating revenues primarily resulted from an increase in well-servicing revenues from our acquisition of Enserco in April 2002. Operating revenues also increased due to a year-over-year increase in drilling revenues. Drilling revenues increased due to our April 2002 acquisition of Enserco and our November 2001 acquisition of Command Drilling Corporation. These acquisitions increased our position in Canada with assets that are relatively new and in excellent condition, allowing us to provide services to many of our key U.S. customers who have increased their presence in Canada because of its increasingly strategic importance to the North American gas supply market. Rig years in Canada increased to 22.9 years during 2002 from 20.4 years during 2001. Rig years peaked during the fourth quarter of 2002, averaging 29.6 years for the period. Canadian well-servicing hours totaled 164,785 hours for the period from April 26, 2002, the date we acquired Enserco, through December 31, 2002. Adjusted income derived from operating activities for Canada decreased primarily due to the addition of well-servicing operations in 2002 which tend to have lower margins than drilling operations, lower average margins in our drilling operations caused by the downward pressure on pricing for much of the first half of 2002, as well as increased general and administrative expenses caused by our Enserco and Command acquisitions and the related build-up of our Canadian operations during 2002.

International Operating revenues and Earnings from unconsolidated affiliates, and adjusted income derived from operating activities totaled $320.2 million and $76.1 million, respectively, in 2002, representing increases of 13% and 30%, respectively, compared to 2001. These increases resulted from higher rig years and higher average dayrates in our Middle East operations, primarily in Saudi Arabia and Yemen, and our African operations, primarily in Algeria. International rig years increased slightly to 55.1 years during 2002 from 54.5 years during 2001.

Oil and Gas Operating revenues and adjusted loss derived from operating activities for our Oil and Gas operating segment totaled $7.2 million and $1.1 million, respectively, in 2002, representing an increase of 31% and a decrease of 44%, respectively, compared to 2001. The increase in Operating revenues resulted from increased investment in selective oil and gas exploration, development and production operations during 2002. We realized an adjusted loss derived from operating activities in 2002 compared to adjusted income derived from operating activities in 2001 as a result of increased depletion expense driven by increased oil and gas production.

Other Operating Segments Operating revenues and Earnings from unconsolidated affiliates for our Other Operating Segments totaled $174.8 million in 2002, representing a decrease of 33% compared to 2001. Adjusted income derived from operating activities totaled $24.7 million in 2002, representing a 72% decrease compared to 2001. These decreases resulted primarily from lower average dayrates and weak market conditions in our marine transportation and supply services and U.S. trucking operations and from decreased top drive sales.

Other Financial Information General and administrative expenses increased by $6.4 million, or 5%, in 2002 compared to 2001 as a result of increases related to our Canadian acquisitions partially offset by decreased rig activity. As a percentage of operating revenues, general and administrative expenses increased during 2002 compared to 2001 (9.7% vs. 6.2%) as these expenses were spread over a lower revenue base.

Depreciation and amortization, and depletion expense increased by $5.5 million, or 3%, in 2002 compared to 2001 as a result of significant capital expenditures and acquisitions during 2001 and 2002. This was partially offset by decreased rig activity, an extension of certain of our fixed asset depreciable lives and the required discontinuance of goodwill amortization. Effective October 1, 2001, we changed the depreciable lives of our drilling and workover rigs from 4,200 to 4,900 active days, our jack-up rigs from 4,200 to 8,030 active days and certain other drilling equipment lives, to better reflect the estimated useful lives of these assets. The effect of this change in accounting estimate was accounted for on a prospective basis beginning October 1, 2001 and decreased depreciation expense by $28.7 million and $8.6 million in 2002 and 2001, respectively. On January 1, 2002, we adopted Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets," which resulted in us no longer amortizing goodwill. The effect of this change, if applied to 2001, would have decreased amortization expense by approximately $7.1 million for the year ended December 31, 2001.

Interest expense increased in 2002 as a result of higher average outstanding debt balances, resulting from the issuance of our $225 million aggregate principal amount of 4.875% senior notes and $275 million aggregate principal amount of 5.375% senior notes in August 2002, which added $8.3 million to interest expense in 2002. Interest income decreased in 2002 due to lower average yields on investments resulting from the overall declining interest rate environment partially offset by higher average cash and marketable securities balances.

Other income decreased in 2002, compared to 2001, resulting primarily from the following: a gain on extinguishment of debt of $15.3 million recorded in 2001, a year-to-year decrease in gains on long-term assets of $5.7 million and corporate reorganization expense of $3.8 million recorded in 2002.

Our effective income tax rate was 14% during 2002 compared to 36% during 2001 due primarily to an increase in international earnings as a percentage of our overall earnings. Our international earnings, other than earnings from our Canadian operations, generally are taxed at lower rates than earnings from our U.S. operations. Our corporate reorganization also had the effect of lowering our effective income tax rate. The tax benefit attributable to our corporate reorganization in 2002 was approximately $13.0 million ($.09 per diluted share). Excluding the $13.0 million in tax savings related to the corporate reorganization, our effective tax rate for 2002 was 23%.

Liquidity and Capital Resources

Cash Flows

Our cash flows primarily depend on the level of spending by our primary customers, oil and gas companies, for exploration, development and production activities. Sustained increases or decreases in the price of natural gas or oil could have a material impact on these activities, and could also materially affect our cash flows. Certain uses of cash, such as the level of non-sustaining capital expenditures, purchases and sales of marketable securities, issuances of debt and repurchases of our common shares are within our control and are adjusted as necessary based on market conditions. The following is a discussion of our cash flows for the years ended December 31, 2003 and 2002.

Operating Activities Net cash provided by operating activities totaled $395.8 million during 2003 compared to net cash provided by operating activities totaling $400.9 million during 2002. During 2003 net income was increased for non-cash items such as depreciation and amortization, and depletion, and was reduced for changes in our working capital and other balance sheet accounts and for our deferred income tax benefit. During 2002 net income was increased for non-cash items such as depreciation and amortization, depletion, deferred income taxes, and from changes in our working capital accounts.

Investing Activities Net cash used for investing activities totaled $408.3 million during 2003 compared to net cash used for investing activities totaling $654.3 million during 2002. During 2003 cash was used for purchases, net of sales, of marketable and non-marketable securities and capital expenditures. During 2002 cash was used for our acquisitions of Ryan and Enserco, capital expenditures, and for purchases, net of sales, of marketable and non-marketable securities.

Financing Activities Net cash provided by financing activities totaled $171.5 million during 2003 compared to net cash provided by financing activities totaling $466.7 million during 2002. During 2003 cash was provided by approximately $688.5 million in net proceeds from the issuance of our $700 million zero coupon senior exchangeable notes on June 10, 2003 and was used for the reduction of long-term debt of $544.5 million. Cash was also provided during the current year by our receipt of proceeds totaling $26.3 million from the exercise of options and warrants to acquire our common shares. During 2002 cash was provided by the proceeds of $493.0 million from the issuance of senior notes in August 2002 and by our receipt of proceeds totaling $12.9 million from the exercise of options to acquire our common shares, and was used for the reduction of long-term debt of $30.8 million.

On June 10, 2003, we completed a private placement of $700 million aggregate principal amount of zero coupon senior exchangeable notes due 2023. The notes were reoffered by the initial purchaser of the notes to qualified institutional buyers under Rule 144A of the Securities Act of 1933, as amended, and outside the United States in accordance with Regulation S under the Securities Act. The notes do not bear interest, do not accrete and have a zero yield to maturity, unless we become obligated to pay contingent interest as defined in the note indenture. See our discussion of additional provisions of these notes in Note 8 to our accompanying consolidated financial statements. Cash provided by issuance of the notes, net of issuance costs, totaled $688.5 million.

We used a portion of the net proceeds from the issuance of the notes to redeem the remaining outstanding principal amount of our $825 million zero coupon convertible senior debentures due 2020 on June 20, 2003. The redemption price was $655.50 per $1,000 principal amount of the debentures for an aggregate redemption price paid of approximately $494.9 million. The remainder of the proceeds of the notes were invested in cash and marketable securities and will be used for general corporate purposes, including payments at the maturity of our 6.8% senior notes due April 15, 2004.

On April 1, 2003, we redeemed our 8.625% senior subordinated notes due April 2008 and all associated guarantees at a redemption price of $1,043.13 per $1,000 principal amount of the notes together with accrued and unpaid interest to the date of redemption for an aggregate redemption price of $45.2 million.

Future Cash Requirements

As of December 31, 2003, we had long-term debt, including current maturities, of $2.3 billion and cash and cash equivalents and investments in marketable securities of $1.5 billion. See table included under *Fair Value of Financial Instruments* below for a breakout of the components of our long-term debt as of December 31, 2003.

Our 6.8% senior notes are due April 15, 2004 for an aggregate principal amount of $295.3 million. This amount is classified in current liabilities in our consolidated balance sheet as of December 31, 2003.

Our $1.381 billion zero coupon convertible senior debentures due 2021 can be put to us on February 5, 2006, February 5, 2011 and February 5, 2016, for a purchase price equal to the issue price plus accrued original issue discount to the date of repurchase. Our $700 million zero coupon senior exchangeable notes due 2023 can be put to us on June 15, 2008, June 15, 2013 and June 15, 2018, for a purchase price equal to 100% of the principal amount of the notes plus contingent interest and additional amounts, if any. We may elect to pay all or a portion of the purchase price of the debentures and the notes in common shares instead of cash, depending upon our cash balances and cash requirements at that time. We do not presently anticipate using common shares to satisfy any such future purchase obligations. In accordance with the indenture with respect to the debentures, we cannot redeem the $1.381 billion debentures before February 5, 2006. After that date, we may redeem all or a portion of the debentures for cash at any time at their accreted value.

As of December 31, 2003, we had outstanding capital expenditure purchase commitments of approximately $26.1 million, primarily for rig-related enhancing and sustaining capital expenditures. In addition, we estimate that we will contribute approximately $57.1 million and $2.5 million in conjunction with our agreements with El Paso Corporation during 2004 and 2005, respectively. In addition to the purchase commitments discussed above, projected capital expenditures for 2004 for sustaining and known new construction and enhancement projects are expected to total approximately $340 million.

We have historically completed a number of acquisitions and will continue to evaluate opportunities to acquire assets or businesses to enhance our operations. Several of our previous acquisitions were funded through issuances of our common shares. Future acquisitions may be paid for using existing cash or issuance of debt or Nabors shares. Such capital expenditures and acquisitions will depend on our view of market conditions and other factors.

Historical capital expenditures and acquisitions of businesses, which represent the portion of the purchase price of acquisitions allocated to fixed assets and goodwill based on their fair market value, are classified as follows:

	Year Ended December 31,		
(In thousands)	2003	2002	2001
Sustaining	$ 159,932	$ 102,633	$ 231,683
Enhancement	110,852	136,837	398,513
Acquisitions	71,549	449,365	155,671
New Construction	15,060	14,008	17,374
	$ 357,393	$ 702,843	$ 803,241

The following table summarizes our contractual cash obligations as of December 31, 2003:

	Payments Due by Period				
(In thousands)	Total	< 1 Year	1–3 Years	3–5 Years	Thereafter
Contractual cash obligations:					
Long-term debt:					
Principal	$ 2,326,192	$ 299,392	$ 826,800[1]	$ 700,000[2]	$ 500,000
Interest	195,045	31,606	51,501	51,501	60,437
Operating leases[3]	24,804	10,096	9,883	2,561	2,264
Capital expenditure purchase commitments[3]	85,786	83,224	2,562	–	–
Time charter commitment[4]	92,626	27,056	53,964	11,606	–
Employment contracts[3]	7,942	1,808	3,061	1,222	1,851
Pension funding obligations[5]	1,490	1,490	–	–	–
Total contractual cash obligations	$ 2,733,885	$ 454,672	$ 947,771	$ 766,890	$ 564,552

(1) Represents our $1.381 billion zero coupon convertible senior debentures which can be put to us on February 5, 2006.

(2) Represents our $700 million zero coupon exchangeable notes which can be put to us on June 15, 2008.

(3) See Note 13 to the accompanying consolidated financial statements.

(4) Relates to our future commitments under our time charter with Sea Mar Management LLC. See *Related Party Transactions* below.

(5) See Note 11 to the accompanying consolidated financial statements.

Financial Condition and Sources of Liquidity

Our primary sources of liquidity are cash and cash equivalents, marketable securities and cash generated from operations. As of December 31, 2003, we had cash and cash equivalents and investments in marketable securities of $1.5 billion (including $612.4 million of long-term marketable securities) and working capital of $917.3 million. This compares to cash and cash equivalents and investments in marketable securities of $1.3 billion (including $459.1 million of long-term marketable securities) and working capital of $618.5 million as of December 31, 2002.

The increase in cash and cash equivalents and investments in marketable securities, and working capital relates primarily to the issuance of our $700 million zero coupon senior exchangeable notes in June 2003, which resulted in net proceeds of $688.5 million, partially offset by reductions in long-term debt of $544.5 million during 2003. Cash and cash equivalents, investments in marketable securities, and working capital were also increased during 2003 by cash provided by operating activities totaling $395.8 million and decreased by capital expenditures of $353.4 million during the year. The increase in working capital was partially offset by the reclassification in 2003 of $295.3 million principal amount of our 6.8% senior notes due April 15, 2004 to current liabilities.

Our funded debt-to-capital ratio was 0.48:1 as of December 31, 2003 and 0.49:1 as of December 31, 2002. Our net funded debt-to-capital ratio was 0.23:1 as of December 31, 2003 and 0.26:1 as of December 31, 2002. The funded debt-to-capital ratio is calculated by dividing funded debt by funded debt plus capital. Funded debt is defined as the sum of (1) short-term borrowings, (2) current portion of long-term debt, and (3) long-term debt. Capital is defined as shareholders' equity. The net funded debt-to-capital ratio nets cash and cash equivalents and marketable securities ($1.5 billion and $1.3 billion as of December 31, 2003 and 2002, respectively) against funded debt. This ratio is calculated by dividing net funded debt by net funded debt plus capital. Both of these ratios are a method for calculating the amount of leverage a company has in relation to its capital. Our interest coverage ratio was 6.8:1 as of December 31, 2003, compared to 6.0:1 as of December 31, 2002. The interest coverage ratio is computed by calculating the sum of income before income taxes, interest expense, and depreciation and amortization, and depletion expense and then dividing by interest expense. This ratio is a method for calculating the amount of cash flows available to cover interest expense.

We have three letter of credit facilities and a Canadian line of credit facility with various banks as of December 31, 2003. Availability and borrowings under our credit facilities as of December 31, 2003 are as follows:

(In thousands)	
Credit available	$ 96,825
Letters of credit outstanding	(56,288)
Remaining availability	$ 40,537

We have a shelf registration statement on file with the Securities and Exchange Commission to allow us to offer, from time to time, up to $700 million in debt securities, guarantees of debt securities, preferred shares, depository shares, common shares, share purchase contracts, share purchase units and warrants. We currently have not issued any securities registered under this registration statement.

Our current cash and cash equivalents, investments in marketable securities and projected cash flow generated from current operations are expected to more than adequately finance our sustaining capital expenditures, our debt service requirements, including payments at maturity of our 6.8% senior notes due April 15, 2004, and all other expected cash requirements for the next twelve months.

Off-Balance Sheet Arrangements (Including Guarantees)

We are a party to certain transactions, agreements or other contractual arrangements defined as "off-balance sheet arrangements" that could have a material future effect on our financial position, results of operations, liquidity and capital resources. The most significant of these off-balance sheet arrangements involve our time charter lease obligation with Sea Mar Management LLC and certain other agreements in which we provide financial or performance assurance to third parties. See *Related Party Transactions* below and Note 12 to our accompanying consolidated financial statements for a discussion of our Sea Mar Management LLC time charter arrangement. Certain of our other agreements involving financial or performance assurance to third parties serve as guarantees, including standby letters of credit issued on behalf of insurance carriers in conjunction with our workers' compensation insurance program and guarantees of residual value in certain of our operating lease agreements. We have also guaranteed payment of contingent consideration in conjunction with an acquisition in 2002, which is based on future operating results of that business. In addition, we have provided indemnifications to certain third parties which serve as guarantees. These guarantees include indemnification provided by Nabors to our stock transfer agent and our insurance carriers. We are not able to estimate the potential future maximum payments that might be due under our indemnification guarantees.

Management believes the likelihood that we would be required to perform or otherwise incur any significant losses associated with any of these guarantees is remote. The following table summarizes the total maximum amount of financial and performance guarantees issued by Nabors:

	Maximum Amount				
(In thousands)	2004	2005	2006	Thereafter	Total
Financial standby letters of credit	$ 34,186	$ –	$ –	$ –	$ 34,186
Guarantee of residual value in lease agreements	347	684	65	–	1,096
Contingent consideration in acquisition	1,111	1,111	278	–	2,500
Total	$ 35,644	$ 1,795	$ 343	$ –	$ 37,782

Additionally, our $700 million zero coupon senior exchangeable notes issued in June 2003 contain a feature whereby we will be obligated to pay contingent interest during any six-month period from June 15 to December 14 or from December 15 to June 14 commencing on or after June 15, 2008 for which the average trading price of the notes for each day of the applicable five-day trading reference period equals or exceeds 120% of the principal amount of the notes as of the day immediately preceding the first day of the applicable six-month interest period. The amount of contingent interest payable per note in respect to any six-month period will equal 0.185% of the principal amount of a note.

Other Matters

Our Sea Mar division time charters supply vessels to offshore operators in U.S. waters. On February 4, 2004, the United States Coast Guard took several actions which could adversely affect our ability to do so.

The vessels are owned by one of our financing company subsidiaries, but are operated and managed by a U.S. citizen-controlled company pursuant to long-term bareboat charters (see *Related Party Transactions* below). Our Sea Mar division time charters the vessels from this U.S. operating company in connection with our own offshore activities in the Gulf of Mexico and in support of other offshore operators.

On February 4, 2004, the United States Coast Guard adopted final regulations which could cause arrangements like that utilized by Sea Mar to no longer qualify vessels for employment in the U.S. coastwise trades. However, the final regulations contain grandfathering provisions which could permit us to continue coastwise marketing of the vessels until the present bareboat charters terminate. The original term of most of these bareboat charters ends in June 2007, but the charter provides for one or more renewal terms of three to five years. We believe the grandfathering provisions in these final regulations would apply to these renewal terms.

Also, on February 4, 2004, the United States Coast Guard proposed a rule which, if finally adopted, would end the grandfathering provision on February 4, 2007. In these same proposed regulations, the United States Coast Guard is proposing a rule under which time charters from a U.S. citizen bareboat charterer like the charter to Sea Mar would no longer be permitted. However, we believe that if this rule is adopted, the grandfathering provision would apply to the preexisting Sea Mar arrangement.

Additionally, on February 4, 2004, the United States Coast Guard notified us that it is considering an appeal of the United States Coast Guard's original issuance in June 2002 of the coastwise trade endorsements for the vessels bareboat chartered to the U.S. citizen qualified company. The coastwise trade endorsements on the documents of the vessels issued by the United States Coast Guard authorize the vessels to engage in the U.S. coastwise trade. If the appeal is decided against us, we could lose the ability to market the vessels for use in U.S. waters.

During 2003 adjusted income derived from operating activities for our Sea Mar division represented approximately 3.8% of our consolidated adjusted income derived from operating activities. We currently expect that this percentage will decrease to approximately 0.9% in 2004.

Forward-Looking Statements

We often discuss expectations regarding our future markets, demand for our products and services, and our performance in our annual and quarterly reports, press releases, and other written and oral statements. Statements that relate to matters that are not historical facts are "forward-looking statements" within the meaning of the safe harbor provisions of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These "forward-looking statements" are based on an analysis of currently available competitive, financial and economic data and our operating plans. They are inherently uncertain and investors should recognize that events and actual results could turn out to be significantly different from our expectations. By way of illustration, when used in this document, words such as "anticipate," "believe," "expect," "plan," "intend," "estimate," "project," "will," "should," "could," "may," "predict" and similar expressions are intended to identify forward-looking statements.

You should consider the following key factors when evaluating these forward-looking statements:

- fluctuations in worldwide prices of and demand for natural gas and oil;
- fluctuations in levels of natural gas and oil exploration and development activities;

• fluctuations in the demand for our services;
• the existence of competitors, technological changes and developments in the oilfield services industry;
• the existence of operating risks inherent in the oilfield services industry;
• the existence of regulatory and legislative uncertainties;
• the possibility of changes in tax laws;
• the possibility of political instability, war or acts of terrorism in any of the countries in which we do business; and
• general economic conditions.

Our businesses depend, to a large degree, on the level of spending by oil and gas companies for exploration, development and production activities. Therefore, a sustained increase or decrease in the price of natural gas or oil, which could have a material impact on exploration, development and production activities, could also materially affect our financial position, results of operations and cash flows.

The above description of risks and uncertainties is by no means all-inclusive, but is designed to highlight what we believe are important factors to consider. For a more detailed description of risk factors, please refer to our Form 10-K filed with the Securities and Exchange Commission under Part I, Item I, "Business - Risk Factors."

Recent Accounting Pronouncements

In November 2002 the Financial Accounting Standards Board (FASB) issued Interpretation No. 45 (FIN 45), "Guarantor's Accounting and Disclosure Requirements, Including Guarantees of Indebtedness of Others." FIN 45 requires that upon issuance of certain types of guarantees, a guarantor recognize and account for the fair value of the guarantee as a liability. FIN 45 contains exclusions to this requirement, including the exclusion of a parent's guarantee of its subsidiaries' debt to third parties. The initial recognition and measurement provisions of FIN 45 have been applied on a prospective basis for guarantees issued or modified after December 31, 2002. During 2003 we issued new standby letters of credit which serve as guarantees under the provisions of FIN 45. The application of the recognition and measurement provisions of FIN 45 to these guarantees was insignificant. The disclosure requirements of FIN 45 are effective for financial statements of both interim and annual periods ending after December 15, 2002, and are included in Note 13 to our accompanying consolidated financial statements and under the heading *Off-Balance Sheet Arrangements (Including Guarantees)* above.

In January 2003 the FASB issued Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities," which addresses the consolidation of variable interest entities (VIEs) by business enterprises that are the primary beneficiaries. A VIE is an entity that does not have sufficient equity investment at risk to permit it to finance its activities without additional subordinated financial support, or whose equity investors lack the characteristics of a controlling financial interest. The primary beneficiary of a VIE is the enterprise that has the majority of the risks or rewards associated with the VIE. In December 2003 the FASB issued a revision to FIN 46, Interpretation No. 46R (FIN 46R), to clarify some of the provisions of FIN 46, and to exempt certain entities from its requirements. Application of FIN 46R is required in financial statements of public entities that have interests in structures that are commonly referred to as special-purpose entities for periods ending after December 15, 2003. Application for all other types of VIEs is required in financial statements for periods ending after March 15, 2004. We have no interests in structures that are commonly referred to as special-purpose entities and therefore have not adopted FIN 46R as of December 31, 2003. We do not expect our adoption of FIN 46R to materially affect our financial position, results of operations or cash flows.

In May 2003 the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 149 is effective in relation to certain issues for fiscal quarters that began prior to June 15, 2003 and for certain contracts entered into after June 30, 2003. The adoption of SFAS 149 had no impact on our financial position, results of operations or cash flows as of and for the year ended December 31, 2003.

In May 2003 the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." SFAS 150 establishes standards for how an issuer classifies and measures in its statement of financial position certain financial instruments with characteristics of both liabilities and equity. In accordance with the standard, financial instruments that embody obligations for the issuer are required to be classified as liabilities. SFAS 150 is effective for such financial instruments, except for those that apply to mandatorily redeemable noncontrolling interests, entered into or modified after May 31, 2003, and otherwise was effective for such financial instruments, except for those that apply to mandatorily redeemable noncontrolling interests, at the beginning of the third quarter of 2003. The adoption of SFAS 150 had no initial impact on our financial position, results of operations or cash flows as of and for the year ended December 31, 2003.

In December 2003 the FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits," that replaces existing FASB disclosure requirements for pensions. The revised SFAS 132 is effective for fiscal years ending after December 15, 2003, and for quarters beginning after December 15, 2003. The disclosures related to our pension plan included in Note 11 to our accompanying consolidated financial statements include all relevant disclosures required by the revised SFAS 132.

Related Party Transactions

Pursuant to his employment agreement entered into in October 1996, we provided an unsecured, non-interest bearing loan of approximately $2.9 million to Nabors' Deputy Chairman, President and Chief Operating Officer. This loan is due on September 30, 2006.

Pursuant to their employment agreements, Nabors and its Chairman and Chief Executive Officer, Deputy Chairman, President and Chief Operating Officer, and certain other key employees entered into split-dollar life insurance agreements pursuant to which we pay a portion of the premiums under life insurance policies with respect to these individuals and, in certain instances, members of their families. Under these agreements, we are reimbursed for such premiums upon the occurrence of specified events, including the death of an insured individual. Any recovery of premiums paid by Nabors could potentially be limited to the cash surrender value of these policies under certain circumstances. As such, the values of these policies are recorded at their respective cash surrender values in our consolidated balance sheets. We have made premium payments to date totaling $12.4 million related to these policies. The cash surrender value of these policies of approximately $11.4 million and $8.7 million is included in other long-term assets in our consolidated balance sheets as of December 31, 2003 and 2002, respectively.

Under the Sarbanes-Oxley Act of 2002, the payment of premiums by Nabors under the agreements with our Chairman and Chief Executive Officer and with our Deputy Chairman, President and Chief Operating Officer may be deemed to be prohibited loans by us to these individuals. We have paid no premiums related to our agreements with these individuals since the adoption of the Sarbanes-Oxley Act and have postponed premium payments related to our agreements with these individuals.

In the ordinary course of business, we enter into various rig leases, rig transportation and related oilfield services agreements with our Alaskan and Saudi Arabian unconsolidated affiliates at market prices. Additionally, we own certain marine vessels that are chartered under a bareboat charter arrangement to Sea Mar Management LLC, which is wholly-owned by Sea Mar Investco LLC, an entity in which we own a 25% interest. Sea Mar Management has entered into a time charter of these vessels with a subsidiary of ours, which then time charters the vessels to various third-party customers. Revenues from these business transactions totaled $81.6 million, $65.7 million and $26.9 million for the years ended December 31, 2003, 2002 and 2001, respectively. Expenses from these business transactions totaled $52.0 million, $32.1 million and $4.8 million for the years ended December 31, 2003, 2002 and 2001, respectively. Additionally, we had accounts receivable from these affiliated entities of $24.0 million and $53.3 million as of December 31, 2003 and 2002, respectively. We had accounts payable to these affiliated entities of $3.7 million and $1.1 million as of December 31, 2003 and 2002, respectively.

Critical Accounting Policies and Accounting Estimates

Our consolidated financial statements are impacted by the accounting policies used and the estimates and assumptions made by management during their preparation. The following is a discussion of our critical accounting policies and critical accounting estimates.

Critical Accounting Policies We have identified below accounting policies that are of particular importance to the portrayal of our financial position, results of operations and cash flows and which require the application of significant judgment by management.

Property, Plant and Equipment Property, plant and equipment, including renewals and betterments, are stated at cost, while maintenance and repairs are expensed currently. Interest costs applicable to the construction of qualifying assets are capitalized as a component of the cost of such assets. We review our assets for impairment when events or changes in circumstances indicate that the net book value of property, plant and equipment may not be recovered over its remaining service life. Provisions for asset impairment are charged to income when the sum of estimated future cash flows, on an undiscounted basis, is less than the asset's net book value. When impairment is indicated, an impairment charge is recorded based on an estimate of future cash flows on a discounted basis.

Self-Insurance Accruals We are self-insured for certain losses relating to workers' compensation, employers' liability, general liability, automobile liability and property damage. We maintain actuarially-determined accruals in our consolidated balance sheets to cover the self-insurance retentions. We are also self-insured for certain other losses relating to rig, equipment, property, business interruption and political, war and terrorism risks.

Revenue Recognition We recognize revenues and costs on daywork contracts daily as the work progresses. For certain contracts, we receive lump-sum payments for the mobilization of rigs and other drilling equipment. Mobilization revenues earned and the related direct costs incurred for the mobilization are deferred and recognized over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred.

We recognize revenue for top drives and instrumentation systems we manufacture when the earnings process is complete. This generally occurs when products have been shipped, title and risk of loss have been transferred, collectibility is probable, and pricing is fixed and determinable.

We recognize, as operating revenue, proceeds from business interruption insurance claims in the period that the applicable proof of loss documentation is received. Proceeds from casualty insurance settlements in excess of the carrying value of damaged assets are recognized in other income in the period that the applicable proof of loss documentation is received.

We recognize reimbursements received for out-of-pocket expenses incurred as revenues and account for out-of-pocket expenses as direct costs.

We recognize revenue on our interests in oil and gas properties as production occurs and title passes.

Income Taxes We are a Bermuda-exempt company and are not subject to income taxes in Bermuda. Consequently, income taxes have been provided based on the tax laws and rates in effect in the countries in which our operations are conducted and income is earned. The income taxes in these jurisdictions vary substantially. Our effective tax rate for financial statement purposes will continue to fluctuate from year to year as our operations are conducted in different taxing jurisdictions.

For U.S. and other foreign jurisdiction income tax purposes, we have net operating and other loss carryforwards that we are required to assess annually for potential valuation allowances. We consider the sufficiency of existing temporary differences and expected future earnings levels in determining the amount, if any, of valuation allowance required against such carryforwards.

We do not provide for U.S. income and foreign withholding taxes on unremitted earnings of our international subsidiaries, as these earnings are considered permanently reinvested. It is not practicable to estimate the amount of deferred income taxes associated with these unremitted earnings.

In circumstances where our drilling rigs and other assets are operating in certain foreign taxing jurisdictions and it is expected that we will redeploy such assets before they give rise to future tax consequences, we do not recognize any deferred tax liabilities on the earnings from these assets.

Critical Accounting Estimates The preparation of our financial statements in conformity with GAAP requires management to make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosures of contingent assets and liabilities at the balance sheet date and the amounts of revenues and expenses recognized during the reporting period. We analyze our estimates based on our historical experience and various other assumptions that we believe to be reasonable under the circumstances. However, actual results could differ from such estimates. The following is a discussion of our critical accounting estimates.

Depreciation and Amortization of Property, Plant and Equipment and Intangible Assets In order to depreciate and amortize our property, plant and equipment and our intangible assets with finite lives, we estimate the useful lives and salvage values of these items. Our estimates may be affected by such factors as changing market conditions, technological advances in the industry or changes in regulations governing the industry.

We provide for the depreciation of our drilling and workover rigs using the units-of-production method over an approximate 4,900-day period, with the exception of our jack-up rigs which are depreciated over an 8,030-day period, after provision for salvage value. When our drilling and workover rigs are not operating, a depreciation charge is provided using the straight-line method over an assumed depreciable life of 20 years, with the exception of our jack-up rigs, where a 30-year depreciable life is used.

Depreciation on our buildings, well-servicing rigs, oilfield hauling and mobile equipment, marine transportation and supply vessels, and other machinery and equipment is computed using the straight-line method over the estimated useful life of the asset after provision for salvage value (buildings – 10 to 30 years; well-servicing rigs – 3 to 15 years; marine transportation and supply vessels – 15 to 25 years; oilfield hauling and mobile equipment and other machinery and equipment – 3 to 10 years). Upon retirement or other disposal of fixed assets, the cost and related accumulated depreciation are removed from the respective accounts and any gains or losses are included in our results of operations.

Impairment of Property, Plant and Equipment Our determination of impairment of our property, plant and equipment requires us to estimate undiscounted future cash flows. Actual impairment charges are recorded using an estimate of discounted future cash flows. The determination of future cash flows requires us to estimate dayrates and utilization in future periods, and such estimates can change based on market conditions, technological advances in the industry or changes in regulations governing the industry.

Income Taxes Under U.S. federal tax law, the amount and availability of loss carryforwards (and certain other tax attributes) are subject to a variety of interpretations and restrictive tests applicable to Nabors and our subsidiaries. The utilization of such carryforwards could be limited or effectively lost upon certain changes in ownership. Accordingly, although we believe substantial loss carryforwards are available to us, no assurance can be given concerning the realization of such loss carryforwards, or whether or not such loss carryforwards will be available in the future.

Certain events could occur that would materially affect management's estimates and assumptions regarding the deferred portion of our income tax provision, including estimates of future tax rates applicable to the reversal of tax differences, the classification of timing differences as temporary or permanent and any valuation allowance recorded as a reduction to our deferred tax assets.

Allowance for Doubtful Accounts We estimate our allowance for doubtful accounts based on an analysis of historical collection activity and specific identification of overdue accounts. Factors that may affect this estimate include changes in the financial position of a major customer.

Litigation and Insurance Reserves We estimate our reserves related to litigation and insurance based on the facts and circumstances specific to the litigation and insurance claims and our past experience with similar claims. The actual outcome of litigated and insured claims could differ significantly from estimated amounts. As discussed under *Self-Insurance Accruals* above, we maintain actuarially-determined accruals in our consolidated balance sheets to cover self-insurance retentions. These accruals are based on certain assumptions developed utilizing historical data to project future losses. Loss estimates in the calculation of these accruals are adjusted based upon actual claim settlements and reported claims.

Fair Value of Assets Acquired and Liabilities Assumed We estimate the values of those assets acquired and liabilities assumed in business combinations, which involves the use of various assumptions. These estimates may be affected by such factors as changing market conditions, technological advances in the industry or changes in regulations governing the industry. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, and the resulting amount of goodwill, if any. Our adoption of SFAS 142 on January 1, 2002 requires us to test for impairment annually the goodwill and intangible assets with indefinite useful lives recorded in business combinations. This requires us to estimate the fair values of our own assets and liabilities at the reporting unit level. Therefore, considerable judgment, similar to that described above in connection with our estimation of the fair value of an acquired company, is required to assess goodwill and certain intangible assets for impairment.

Cash Flow Estimates Our estimates of future cash flows are based on the most recent currently available market and operating data for the applicable asset or reporting unit at the time the estimate is made. Our cash flow estimates are used to determine certain tax-related valuations and for asset impairment analyses.

Stock-Based Compensation We account for stock-based compensation using the intrinsic value method presented by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." However, in accordance with SFAS No. 148, "Accounting for Stock-Based Compensation – an Amendment to FAS 123," we must estimate the fair market value of our outstanding stock-based compensation awards for disclosure purposes. In so doing, we use an option-pricing model (Black-Scholes), which requires various assumptions as to interest rates, volatility, dividend yield and expected lives of awards.

Quantitative and Qualitative Disclosures About Market Risk

We may be exposed to certain market risks arising from the use of financial instruments in the ordinary course of business. This risk arises primarily as a result of potential changes in the fair market value of financial instruments that would result from adverse fluctuations in foreign currency exchange rates, credit risk, interest rates, and marketable and non-marketable security prices as discussed below.

Foreign Currency Risk We operate in a number of international areas and are involved in transactions denominated in currencies other than U.S. dollars, which exposes us to foreign exchange rate risk. The most significant exposures arise in connection with our operations in Canada and Saudi Arabia, which usually are substantially unhedged. For our unconsolidated affiliate in Saudi Arabia, upon renewal of our contracts, we have been converting Saudi riyal-denominated contracts to U.S. dollar-denominated contracts in order to reduce our exposure to the Saudi riyal, even though that currency has been pegged to the U.S. dollar at a rate of 3.745 Saudi riyals to 1.00 U.S. dollar since 1986. We cannot guarantee that we will be able to convert future Saudi riyal-denominated contracts to U.S. dollar-denominated contracts or that the Saudi riyal exchange rate will continue in effect as in the past.

At various times, we utilize local currency borrowings (foreign currency-denominated debt), the payment structure of customer contracts and foreign exchange contracts to selectively hedge our exposure to exchange rate fluctuations in connection with monetary assets, liabilities, cash flows and commitments denominated in certain foreign currencies. A foreign exchange contract is a foreign currency transaction, defined as an agreement to exchange different currencies at a given future date and at a specified rate. A hypothetical 10% decrease in the value of all our foreign currencies relative to the U.S. dollar as of December 31, 2003 would result in an $11.2 million decrease in the fair value of our net monetary assets denominated in currencies other than U.S. dollars.

Credit Risk Our financial instruments that potentially subject us to concentrations of credit risk consist primarily of cash equivalents, investments in marketable and non-marketable securities, accounts receivable, and our interest rate swap and range cap and floor transactions. Cash equivalents, such as deposits and temporary cash investments, are held by major banks or investment firms. Our investments in marketable and non-marketable securities are managed within established guidelines which limit the amounts that may be invested with any one issuer and which provide guidance as to issuer credit quality. We believe that the credit risk in such instruments is minimal. In addition, our trade receivables are with a variety of U.S., international and foreign-country national oil and gas companies. Management considers this credit risk to be limited due to the financial resources of these companies. We perform ongoing credit evaluations of our customers and we generally do not require material collateral. We maintain reserves for potential credit losses, and such losses have been within management's expectations.

Interest Rate, and Marketable and Non-Marketable Security Price Risk Our financial instruments that are potentially sensitive to changes in interest rates include our $1.381 billion zero coupon convertible senior debentures, our $700 million zero coupon senior exchangeable notes, our 6.8%, 4.875% and 5.375% senior notes, our interest rate swap and range cap and floor transactions, our investments in debt securities (including corporate, asset-backed, U.S. Government, Government agencies, foreign government, mortgage-backed debt and mortgage-CMO debt securities) and our investments in overseas funds investing primarily in a variety of public and private U.S. and non-U.S. securities (including asset-backed securities and mortgage-backed securities, global structured asset securitizations, whole loan mortgages, and participations in whole loans and whole loan mortgages), which are classified as non-marketable securities.

We may utilize derivative financial instruments that are intended to manage our exposure to interest rate risks. The use of derivative financial instruments could expose us to further credit risk and market risk. Credit risk in this context is the failure of a counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty would owe us, which can create credit risk for us. When the fair value of a derivative contract is negative, we would owe the counterparty, and therefore, we would not be exposed to credit risk. We attempt to minimize credit risk in derivative instruments by entering into transactions with major financial institutions that have a significant asset base. Market risk related to derivatives is the adverse effect to the value of a financial instrument that results from changes in interest rates. We try to manage market risk associated with interest-rate contracts by establishing and monitoring parameters that limit the type and degree of market risk that we undertake.

Our $700 million zero coupon senior exchangeable notes include a contingent interest provision, discussed under *Liquidity* above, which qualifies as an embedded derivative under SFAS 133, as amended by SFAS 149. This embedded derivative is required to be separated from the notes and valued at its fair value at the inception of the note indenture. Any subsequent change in fair value of this embedded derivative will be recorded in our consolidated statements of income. The fair value of the contingent interest provision at inception of the note indenture was nominal. In addition, there was no significant change in the fair value of this embedded derivative through December 31, 2003, resulting in no impact on our consolidated statement of income for the year ended December 31, 2003.

On October 21, 2002, we entered into an interest rate swap transaction with a third-party financial institution to hedge our exposure to changes in the fair value of $200 million of our fixed rate 5.375% senior notes due 2012, which has been designated as a fair value hedge under SFAS 133, as amended by SFAS 149. Additionally, on October 21, 2002, we purchased a LIBOR range cap and sold a LIBOR floor, in the form of a cashless collar, with the same third-party financial institution with the intention of mitigating and managing our exposure to changes in the three-month U.S. dollar LIBOR rate. This transaction does not qualify for hedge accounting treatment under SFAS 133, as amended by SFAS 149, and any change in the cumulative fair value of this transaction will be reflected as a gain or loss in our consolidated statements of income.

During the years ended December 31, 2003 and 2002, we recorded interest savings related to our interest rate swap agreement accounted for as a fair value hedge of $6.8 million and $1.2 million, respectively, which served to reduce interest expense. The fair value of our interest rate swap agreement is recorded as a derivative asset, included in other long-term assets, and totaled approximately $4.2 million and $10.1 million as of December 31, 2003 and 2002, respectively. The carrying value of our 5.375% senior notes has been increased by the same amount as of December 31, 2003 and 2002.

The fair value of our range cap and floor transaction is recorded as a derivative liability, included in other long-term liabilities, and totaled approximately $3.7 million and $3.8 million as of December 31, 2003 and 2002, respectively. We recorded losses of approximately $1.1 million and $3.8 million for the years ended December 31, 2003 and 2002, respectively, related to this derivative instrument; such amounts are included in other income in our consolidated statements of income. The loss in the current year is comprised of the recognition of approximately $1.2 million of expense in 2003 related to the settlement of amounts due to the counterparty for our range cap and floor derivative instrument discussed below, which were partially offset by a gain of approximately $.1 million resulting from the change in cumulative fair value of this derivative instrument during 2003. As a result of the three-month U.S. dollar LIBOR rate being below our 2.665% floor on August 15, 2003 (such rate was 1.13%), we paid approximately $.8 million to the counterparty on November 15, 2003 as settlement for the three-month period from August 15 to November 15, 2003. As a result of the three-month U.S. dollar LIBOR rate being below our 2.665% floor on November 15, 2003 (such rate was 1.18%), we are obligated to pay, on February 15, 2004, approximately $.8 million to the counterparty as settlement for amounts due for the three-month period from November 15, 2003 to February 15, 2004. We recorded the payment of approximately $.8 million made on November 15, 2003 and approximately $.4 million of the obligation due on February 15, 2004 as expense in other income in 2003 and will record the remaining amount of approximately $.4 million due on February 15, 2004 in the first quarter of 2004.

A hypothetical 10% adverse shift in quoted interest rates as of December 31, 2003 would decrease the fair values of our interest rate swap, and range cap and floor, by approximately $6.4 million and $.9 million, respectively.

Fair Value of Financial Instruments The fair value of our fixed rate long-term debt is estimated based on quoted market prices or prices quoted from third-party financial institutions. The carrying and fair values of our long-term debt, including the current portion, are as follows:

	December 31, 2003		
(In thousands, except interest rates)	Effective Interest Rate	Carrying Value	Fair Value
4.875% senior notes due August 2009	4.884%	$ 223,499	$ 234,585
5.375% senior notes due August 2012	2.909%[1]	277,248[2]	290,813[2]
$700 million zero coupon senior exchangeable notes due June 2023	0%	700,000	643,651
$1.381 billion zero coupon convertible senior debentures due February 2021	2.5%[3]	784,807	780,880
6.8% senior notes due April 2004	6.8%	295,267	299,681
Other long-term debt	8.25%	4,117	4,117
		$ 2,284,938	$ 2,253,727

[1] Includes the effect of interest savings realized from the interest rate swap executed on October 21, 2002.

[2] Includes $4.2 million related to the fair value of the interest rate swap.

[3] Represents the rate at which accretion of the original discount upon issuance of these debentures is charged to interest expense.

The fair values of our cash equivalents, trade receivables and trade payables approximate their carrying values due to the short-term nature of these instruments. Our cash and cash equivalents and investments in marketable debt and equity securities are included in the table below. The table provided below does not include our investments in non-marketable securities, which are carried at cost.

	December 31, 2003		
(In thousands, except interest rates and weighted-average life)	Fair Value	Interest Rates	Weighted-Average Life (Years)
Cash and cash equivalents	$ 579,737	.71%–1.87%	.1
Marketable equity securities:			
Trading	–	N/A	N/A
Available-for-sale	48,843	N/A	N/A
Marketable debt securities:			
Commercial paper and CDs	50,743	1.40%	.1
Corporate debt securities	319,327	1.26%–8.85%	1.2
U.S. Government debt securities	7,103	4.75%–5.87%	.4
Government agencies debt securities	285,358	1.25%–5.63%	1.0
Mortgage-backed debt securities	119	7.50%	–
Mortgage-CMO debt securities	29,275	4.50%–5.00%	–
Asset-backed debt securities	211,585	1.35%–6.79%	.9
	$ 1,532,090		

Our investments in marketable debt securities listed in the above table and a portion of our investments in non-marketable securities are sensitive to changes in interest rates. Additionally, our investment portfolio of marketable debt and equity securities, which are carried at fair value, expose us to price risk. A hypothetical 10% decrease in the market prices for all marketable securities as of December 31, 2003 would decrease the fair value of our available-for-sale securities by $95.2 million.

Report of Independent Auditors

{Nabors Industries Ltd. and Subsidiaries}

To the Shareholders and
Board of Directors of
Nabors Industries Ltd.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of cash flows and of changes in shareholders' equity present fairly, in all material respects, the financial position of Nabors Industries Ltd. and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, Nabors Industries Ltd. changed its method of accounting for goodwill effective January 1, 2002.

PricewaterhouseCoopers LLP

Houston, Texas
March 5, 2004