2002

Financial Review

Selected Financial Data

(Nabors Industries Ltd. and Subsidiaries)

Operating Data[1][2][3]	Year Ended December 31,					Twelve Months Ended December 31, (Unaudited)	Three Months Ended December 31,	Year Ended September 30,			
(In thousands, except per share amounts and ratio data)	2002	2001	2000	1999	1998	1997[4]	1997	1997	1996	1995	1994
Revenues and other income:											
Operating revenues	$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	$484,268
Earnings (losses) from unconsolidated affiliates	14,775	26,334	26,283	3,757	(305)	274	(25)	450	139	–	–
Interest income	34,086	53,973	20,581	8,756	1,480	1,936	93	3,422	2,695	1,694	2,459
Other income, net	3,708	28,650	27,157	8,860	31,626	28,502	2,303	40,747	13,690	5,990	2,718
Total revenues and other income	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	489,445
Costs and other deductions:											
Direct costs	973,910	1,366,967	938,651	446,597	663,551	774,856	199,714	737,780	539,665	434,097	369,677
General and administrative expenses	141,895	135,496	106,504	65,288	77,026	72,478	18,580	68,616	56,862	49,094	47,770
Depreciation and amortization	195,365	189,896	152,413	99,893	84,949	72,350	20,313	66,391	46,117	31,042	26,241
Interest expense	67,068	60,722	35,370	30,395	15,463	16,323	3,979	16,520	11,884	7,611	8,237
Merger expenses	–	–	–	–	–	–	–	1,755	–	–	1,595
Provision for reduction in book value of assets	–	–	–	–	–	–	–	–	–	–	29,686[5]
Total costs and other deductions	1,378,238	1,753,081	1,232,938	642,173	840,989	936,007	242,586	891,062	654,528	521,844	483,206
Income before income taxes	140,774	557,612	229,743	45,629	199,981	209,463	62,616	182,410	81,600	58,628	6,239
Income tax expense	19,285	200,162	92,387	17,925	74,993	73,443	21,289	67,602	11,100	7,524	4,889
Net income	$ 121,489	$ 357,450	$ 137,356	$ 27,704	$ 124,988	$ 136,020	$ 41,327	$ 114,808	$ 70,500	$ 51,104	$ 1,350
Earnings per diluted share	$ .81	$ 2.24	$ .90	$ .23	$ 1.16	$ 1.24	$ .37	$ 1.08	$ .75	$ .57	$ .02
Weighted average number of diluted shares outstanding	149,997	168,790	152,417	120,449	112,555	113,793	116,427	111,975	93,752	89,655	85,620
Capital expenditures and acquisitions of businesses[6]	$ 582,559	$ 784,925	$ 300,637	$ 667,517	$ 313,464	$ 381,009	$ 84,038	$ 396,668	$ 174,483	$ 144,560	$ 62,907
Interest coverage ratio[7]	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	4.9 : 1

Balance Sheet Data[1][2]

(In thousands, except ratio data)	As of December 31, 2002	2001	2000	1999	1998	1997	As of September 30, 1997	1996	1995	1994
Cash and cash equivalents and marketable securities	$1,330,799	$ 918,637	$ 550,953	$ 111,666	$ 47,340	$ 42,135	$ 53,323	$115,866	$ 24,979	$ 65,498
Working capital	618,454	700,816	524,437	195,817	36,822	62,571	70,872	172,091	33,892	77,248
Property, plant and equipment, net	2,781,050	2,433,247	1,821,392	1,669,466	1,127,154	923,402	861,393	511,203	393,464	283,141
Total assets	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	490,273
Long-term debt	1,614,656	1,567,616	854,777	482,600	217,034	226,299	229,507	229,504	51,478	61,879
Stockholders' equity	$2,158,455	$1,857,866	$1,806,468	$1,470,074	$ 867,469	$ 767,340	$ 727,843	$ 457,822	$ 368,750	$ 317,424
Funded debt to capital ratio:										
Gross[8]	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	0.21 : 1
Net[9]	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	0.02 : 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 and financial position for fiscal year 1994 have been retroactively restated to include the results of operations and financial position of Sundowner Offshore Services, Inc., which was acquired by us during October 1994. Our 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) We adopted Emerging Issues Task Force No. 01-14, "Income Statement Characterization of Reimbursements Received for Out-of-Pocket Expenses Incurred" in the second quarter of 2002 and accordingly have reclassified reimbursements received from our customers from direct costs to revenues for the each of the five years in the period ended December 31, 2002. We have not reclassified reimbursements received for any period prior to the year ending December 31, 1998 as these amounts are not material to our overall results of operations and it is not practicable to provide this information for those years.

(4) 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.

(5) Represents reduction in carrying value of our Yemen logistical assets and inventory, as well as facility closure costs in certain international areas, including Yemen, totaling $.35 per diluted share.

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

(7) The interest coverage ratio is computed by calculating the sum of income before income taxes, interest expense, depreciation and amortization expense, and provision for reduction in book value of assets and then dividing by interest expense. This ratio is a method for calculating the amount of cash flows available to cover interest expense.

(8) 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 stockholders' equity.

(9) 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 stockholders' 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 and Africa. Nabors also is one of the largest land well-servicing and workover contractors in the United States and Canada. We own over 900 land workover and well-servicing rigs in the United States, primarily in the southwestern and western United States, and over 200 land workover and well-servicing rigs in Canada. Nabors is a leading provider of offshore platform workover and drilling rigs, and owns 43 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 have a 50% ownership interest in a joint venture in Saudi Arabia, which owns 18 rigs.

To further supplement and complement our primary business, we offer a wide range of ancillary well-site services, including oilfield management, 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 240 rig and oilfield equipment hauling tractor-trailers and a number of cranes, loaders and light-duty vehicles. We maintain over 290 fluid hauling trucks, approximately 700 fluid storage tanks, eight saltwater disposal wells and other auxiliary equipment used in domestic drilling, workover and well-servicing operations. In addition, we own a fleet of 30 marine transportation and supply vessels, primarily in the Gulf of Mexico, which provide transportation of drilling materials, supplies and crews for offshore operations. 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.

Our overall business is conducted through two major segments: (1) Contract Drilling and (2) Manufacturing and Logistics. Our Contract Drilling segment includes our drilling, workover and well-servicing operations, on land and offshore, and our Manufacturing and Logistics segment includes our marine transportation and supply services, top drive manufacturing, directional drilling, rig instrumentation and software, and construction and logistics operations.

A discussion of market trends and outlook for our industry and our results of operations for the last three years are included below. This discussion should be read in conjunction with our consolidated financial statements and notes thereto. Our 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 must 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.

Market Trends and Outlook

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

The oil and gas industry has been subject to extreme volatility in recent years because of significant changes in the demand, supply and pricing of natural gas and oil. In 2000 the price of natural gas and oil improved substantially. The primary contributing factors associated with these price increases were the convergence of supply and demand for natural gas and oil brought about by secular global economic growth and the increasing difficulty, expense and long lead times involved in adding to supply. Rising demand and difficulty in finding and developing additional supply brought the U.S. land rig market to the point where the demand for rigs far exceeded supply. The same situation existed, to a lesser extent, in Canada and U.S. Offshore markets. This high-demand, low-supply environment had a positive impact on our industry.

The tightening of the supply-demand balance continued during the first half of 2001 and along with a colder-than-normal winter provided a catalyst for a spike in natural gas demand, which led to a rapid escalation in natural gas prices. While high natural gas prices fueled a sharp increase in drilling utilization and margins, they soon had an adverse effect on many elements of industrial demand, particularly petrochemicals, and that portion of electric generation that could utilize more economical fuels. Demand was also impacted by a general contraction in the nation's economy beginning in the second half of 2001. These factors led to downward pressure on natural gas prices, leading to a sharp reduction in drilling activity.

Natural gas and oil prices began to recover in the first quarter of 2002 as a result of falling natural gas production and low storage levels. However, a recovery in North American drilling activity did not materialize until early 2003. This time lag in spending was attributable to the need for significantly higher natural gas prices to offset the increased cost and risk of finding and developing incremental gas production along with confidence that prices will sustain at such levels. Sufficiently higher prices did not materialize until the fourth quarter of 2002 and there is generally a two to three quarter lead time in implementing increased spending following higher cash flow.

The higher-than-anticipated pricing for natural gas and oil has continued into 2003, and the continued fall in natural gas production and storage levels resulting from lower drilling activity is increasing the likelihood that higher average prices will be sustained over the intermediate term. We expect these factors to result in an improvement in North American drilling activity during 2003.

The following table sets forth certain industry data that are reflective of historical market conditions:

	Year Ended December 31,			Increase (Decrease)			
	2002	2001	2000	2002 to 2001		2001 to 2000	
Industry data:							
Commodity prices:[1]							
Average Henry Hub natural gas spot price ($/mcf)	$ 3.37	$ 3.96	$ 4.30	$ (.59)	(15%)	$ (.34)	(8%)
Average West Texas intermediate crude oil spot price ($/barrel)	$ 26.17	$ 25.96	$ 30.37	$ .21	1%	$ (4.41)	(15%)
Rig count data:[2]							
Average U.S. land rig count	701	980	762	(279)	(29%)	218	29%
Average U.S. Offshore rig count	113	153	140	(40)	(26%)	13	9%
Average Canadian land rig count	260	336	340	(76)	(23%)	(4)	(1%)
Average International land rig count	506	525	466	(19)	(4%)	59	13%

(1) Source: Bloomberg

(2) Source: Baker Hughes

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)	2002	2001	2000	2002 to 2001		2001 to 2000	
Operating revenues and Earnings from unconsolidated affiliates:							
Contract drilling:[1]							
U.S. Land Drilling[2]	$ 498,421	$ 1,146,463	$ 580,706	$ (648,042)	(57%)	$ 565,757	97%
U.S. Land Well-servicing	294,428	345,785	268,211	(51,357)	(15%)	77,574	29%
U.S. Offshore	105,717	226,078	209,404	(120,361)	(53%)	16,674	8%
Canada	141,497	86,310	75,906	55,187	64%	10,404	14%
International	320,160	282,404	181,926	37,756	13%	100,478	55%
Subtotal contract drilling[3]	1,360,223	2,087,040	1,316,153	(726,817)	(35%)	770,887	59%
Manufacturing and logistics[4][5]	174,775	259,298	176,775	(84,523)	(33%)	82,523	47%
Other[6]	(53,780)	(118,268)	(77,985)	64,488	55%	(40,283)	(52%)
Total	$ 1,481,218	$ 2,228,070	$ 1,414,943	$ (746,852)	(34%)	$ 813,127	57%
Adjusted cash flow derived from operating activities:[7]							
Contract drilling:							
U.S. Land Drilling	$ 132,806	$ 409,760	$ 138,158	$ (276,954)	(68%)	$ 271,602	197%
U.S. Land Well-servicing	58,231	82,402	46,930	(24,171)	(29%)	35,472	76%
U.S. Offshore	19,094	55,107	62,914	(36,013)	(65%)	(7,807)	(12%)
Canada	38,127	37,464	29,945	663	2%	7,519	25%
International	113,641	89,595	64,775	24,046	27%	24,820	38%
Subtotal contract drilling	361,899	674,328	342,722	(312,429)	(46%)	331,606	97%
Manufacturing and logistics	42,704	105,770	63,428	(63,066)	(60%)	42,342	67%
Other[8]	(39,190)	(54,491)	(36,362)	15,301	28%	(18,129)	(50%)
Total	$ 365,413	$ 725,607	$ 369,788	$ (360,194)	(50%)	$ 355,819	96%
Depreciation and amortization	(195,365)	(189,896)	(152,413)	(5,469)	(3%)	(37,483)	(25%)
Adjusted income derived from operating activities[9]	170,048	535,711	217,375	(365,663)	(68%)	318,336	146%
Interest expense	(67,068)	(60,722)	(35,370)	(6,346)	(10%)	(25,352)	(72%)
Interest income	34,086	53,973	20,581	(19,887)	(37%)	33,392	162%
Other income, net	3,708	28,650	27,157	(24,942)	(87%)	1,493	5%
Income before income taxes	$ 140,774	$ 557,612	$ 229,743	$ (416,838)	(75%)	$ 327,869	143%
Net cash provided by operating activities[7]	$ 372,445	$ 695,085	$ 219,448	$ (322,640)	(46%)	$ 475,637	217%
Rig years:[10]							
U.S. Land Drilling	112.3	220.6	166.8	(108.3)	(49%)	53.8	32%
U.S. Offshore	14.5	28.8	30.8	(14.3)	(50%)	(2.0)	(6%)
Canada	22.9	20.4	21.5	2.5	12%	(1.1)	(5%)
International	55.1	54.5	43.7	.6	1%	10.8	25%
Total rig years	204.8	324.3	262.8	(119.5)	(37%)	61.5	23%
Rig hours:[11]							
U.S. Land Well-servicing	1,014,657	1,170,104	1,110,920	(155,447)	(13%)	59,184	5%
Canada Well-servicing[12]	164,785	–	–	164,785	–	–	–
Total rig hours	1,179,442	1,170,104	1,110,920	9,338	1%	59,184	5%

[1] This segment includes our drilling, workover and well-servicing operations, on land and offshore.

[2] U.S. Land Drilling is comprised of our Alaska and U.S. Lower 48 drilling operations.

[3] Includes Earnings from unconsolidated affiliates, accounted for by the equity method, of $3.9 million, $9.0 million and $6.8 million for 2002, 2001 and 2000, respectively.

[4] This segment includes our marine transportation and supply services, 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 $10.9 million, $17.3 million and $19.5 million for 2002, 2001 and 2000, respectively.

[6] Includes the elimination of inter-segment manufacturing and logistics sales.

(7) Adjusted cash flow derived from operating activities is computed by: subtracting direct costs and general and administrative expenses 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 based on several criteria, including adjusted cash flow derived from operating activities, because it believes that this financial measure is an accurate reflection of the ongoing performance of our business units. The following is a reconciliation of net cash provided by operating activities from our consolidated statements of cash flows, which is a GAAP measure, to this non-GAAP measure:

	Year Ended December 31,		
(In thousands)	2002	2001	2000
Net cash provided by operating activities	$ 372,445	$ 695,085	$ 219,448
Interest expense	67,068	60,722	35,370
Interest income	(34,086)	(53,973)	(20,581)
Other income	(3,708)	(28,650)	(27,157)
Current income tax expense	10,185	83,718	19,594
Deferred financing costs amortization	(5,122)	(6,339)	(183)
Discount amortization on zero coupon debentures	(30,790)	(31,832)	(6,625)
Amortization of loss on cash flow hedges	(50)	–	–
Gains on long-term assets, net	4,570	10,246	1,713
Gains (losses) on marketable securities and warrants	2,877	(474)	18,800
Loss on derivative instruments	(1,983)	–	–
Sales of marketable securities, trading	–	–	(401)
Foreign currency transaction gains	486	419	1,441
(Loss) gain on early extinguishment of debt	(202)	15,330	3,036
Equity in earnings from unconsolidated affiliates, net of dividends	4,900	15,833	10,333
(Increase) decrease, net of effects from acquisitions, from changes in working capital accounts	(21,177)	(34,478)	115,000
Adjusted cash flow derived from operating activities	$ 365,413	$ 725,607	$ 369,788

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

(9) Adjusted income derived from operating activities is computed by: subtracting direct costs, general and administrative expenses, and depreciation and amortization 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. However, management evaluates the performance of our business units and the consolidated company based on several criteria, including adjusted income 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 consolidated income before income taxes, which is a GAAP measure, is provided herein.

(10) Excludes well-servicing rigs. Includes our percentage ownership of rigs from 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.

(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.

2002 Compared to 2001

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

The decrease in our operating results during 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. 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, and the loss of some higher margin workover rigs and an offshore platform operation during the second half of 2002.

Natural gas prices are the primary driver of our U.S. Lower 48 land, Canadian and U.S. Offshore (Gulf of Mexico) operations while oil prices are the primary driver of our Alaskan, International and U.S. Well-servicing operations. The Henry Hub natural gas spot price (per Bloomberg) averaged $3.37 per million cubic feet (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. As discussed above, these price increases did not result in a corresponding strengthening of our key North American markets until early 2003.

As had been expected, we realized improvements in our International, Canadian and U.S. Offshore businesses during the fourth quarter of 2002 which were offset by lower results in our U.S. Land Drilling and U.S. Well-servicing businesses. We expect an improvement in all of our business units in 2003 given the high level of natural gas and oil prices sustained during the latter part of 2002 and the beginning of 2003.

Contract Drilling The business units that comprise this segment 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 the contract drilling segment totaled $1.4 billion, and adjusted cash flow derived from operating activities totaled $361.9 million during 2002, representing decreases of 35% and 46%, 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. Land Drilling, U.S. Land Well-servicing and U.S. Offshore business units during 2002 as compared to 2001 were only partially offset by higher revenues from our Canadian and International operations.

U.S. Land Drilling Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $498.4 million and $132.8 million, respectively, representing decreases of 57% and 68%, respectively, as 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. We expect the recovery in natural gas prices that began during 2002 to result in higher rig years in 2003 as demand for our services rebounds. U.S. Land Drilling rig years decreased to 112.3 years during 2002 from 220.6 years during 2001.

U.S. Land Well-servicing Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $294.4 million and $58.2 million, respectively, representing decreases of 15% and 29%, respectively, as 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 1.01 million hours during 2002 from 1.17 million hours during 2001.

U.S. Offshore Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $105.7 million and $19.1 million, respectively, representing decreases of 53% and 65%, respectively, as 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. Sustained higher commodity prices should improve the outlook for our jack-up and platform workover and drilling rigs in 2003. 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 in the fourth quarter of 2002. We also recorded a $2.3 million gain as a result of the 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.

Canadian Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $141.5 million and $38.1 million, respectively, representing increases of 64% and 2%, respectively, as compared to 2001. The increase in Operating revenues and Earnings from unconsolidated affiliates primarily resulted from an increase in well-servicing revenues from the acquisition of Enserco Energy Service Company Inc. in April 2002. Operating revenues also increased due to a year-over-year increase in drilling revenues. Drilling revenues increased due to the April 2002 acquisition of Enserco and the 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, and the growth in this business is expected to continue in 2003. 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 cash flow derived from operating activities for Canada increased at a smaller rate than Operating revenues and Earnings from unconsolidated affiliates due primarily 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 the 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 cash flow derived from operating activities totaled $320.2 million and $113.6 million, respectively, representing increases of 13% and 27%, respectively, as 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.

Manufacturing and Logistics This segment includes our marine transportation and supply services, top drive manufacturing, directional drilling, rig instrumentation and software, and construction and transportation operations. Manufacturing and logistics Operating revenues and Earnings from unconsolidated affiliates were $174.8 million during 2002, representing a decrease of 33% compared with the prior year. Adjusted cash flow derived from operating activities decreased to $42.7 million compared to $105.8 million in the prior year, representing a 60% decrease. Decreases in this segment resulted primarily from lower average dayrates and lower utilization in our marine transportation and supply services and U.S. trucking operations and from decreased top drive sales.

On October 9, 2002, we completed our acquisition of Ryan Energy Technologies Inc., a corporation incorporated under the laws of Alberta, Canada. Ryan manufactures and sells directional drilling and rig instrumentation systems and provides directional drilling, rig instrumentation and data collection services to oil and gas exploration and service companies in the United States, Canada and Venezuela.

Other Financial Information Our gross margin percentage decreased to 34% in 2002 from 38% in 2001. Gross margin percentage is calculated by dividing gross margin by operating revenues. Gross margin is calculated by subtracting direct costs from operating revenues. The decrease in our gross margin percentage is primarily due to a decline in rig activity as well as lower average dayrates in our U.S. Land Drilling and U.S. Offshore operations.

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

Depreciation and amortization expense increased by $5.5 million, or 3%, in 2002 compared to 2001 due to 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 during 2002 due to higher average outstanding debt balances, resulting from the August 2002 issuance of our $225 million aggregate principal amount of 4.875% senior notes due 2009 and $275 million aggregate principal amount of 5.375% senior notes due 2012, which added $8.3 million to interest expense in 2002. Interest income decreased during 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 during 2002, as compared to 2001, due primarily to the following: a gain on extinguishment of debt of $15.3 million recorded during 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 during 2002 (see *Corporate Reorganization* below).

Our effective income tax rate was 14% during 2002 as compared to 36% for 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 was approximately $13.0 million ($.09 per diluted share). 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 being considered by the U.S. Congress, and any responsive action taken by Nabors. Excluding the $13.0 million in tax savings related to the corporate reorganization, our effective tax rate for 2002 was 23%.

2001 Compared to 2000

Our operating results for 2001 were the highest in Nabors' history and significantly above our 2000 results. Operating revenues and Earnings from unconsolidated affiliates for 2001 totaled $2.2 billion, representing an increase of $813.1 million, or 57%, as compared to 2000. Adjusted income derived from operating activities and net income for 2001 totaled $535.7 million and $357.5 million ($2.24 per diluted share), respectively, representing increases of 146% and 160% as compared to 2000.

The increase in our operating results was due to substantial improvements in essentially all of our business units, driven primarily by higher prices for natural gas and oil due to tightness of supply and demand that continued until the beginning of the third quarter of 2001. The increase in the price of natural gas and the sustained higher price of oil during the two-year period from August 1999 to August 2001 resulted in increased spending by our customers for our services. This increased spending was especially evident in our U.S. Lower 48 and Canadian operations for natural gas-related drilling activities and our U.S. Land Well-servicing business which is more directed toward oil.

However, beginning in the third quarter of 2001 a reduction in demand for natural gas caused by high natural gas prices and a general contraction in the nation's economy and, later in the year, warm weather resulted in a build up of excess supply of natural gas. This caused U.S. natural gas prices to decline. Natural gas prices (per the Bloomberg average Henry Hub natural gas spot price), which averaged $5.32 per mcf during the first six months of 2001 and spiked as high as $10.20 per mcf in January 2001, declined significantly, averaging only $2.60 per mcf during the second half of 2001. This significant drop in the price of natural gas reached a low of $1.74 per mcf in November 2001, and resulted in the rapid weakening of natural gas-related drilling activity in the U.S. Lower 48 and U.S. Offshore markets. Oil prices also began to decline during this period with average prices (per the West Texas Intermediate crude oil spot price) of $27.79 per barrel during the first nine months of 2001, decreasing to $20.46 per barrel during the fourth quarter of 2001. The U.S. active land rig count, which averaged 1,022 working rigs during the nine months ended September 30, 2001 and peaked at 1,100 rigs in July 2001, declined to an average of 853 rigs during the fourth quarter of 2001 and a low of 759 rigs in

December 2001. Similarly, our U.S. Lower 48 rig years averaged 231 years during the first nine months of 2001 and declined to an average of 145 years during the fourth quarter of 2001.

Contract Drilling Operating revenues and Earnings from unconsolidated affiliates for the contract drilling segment totaled $2.1 billion, and adjusted cash flow derived from operating activities totaled $674.3 million during 2001, representing increases of 59% and 97%, respectively, compared to the prior year. Rig years (excluding well-servicing rigs) increased to 324.3 years during 2001 from an average of 262.8 years during the prior year. All of our contract drilling operations recorded higher revenues in 2001 compared to 2000 as a result of increased drilling and workover activity and higher average dayrates due to relatively higher natural gas and oil prices during the first six months of 2001.

U.S. Land Drilling Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $1.1 billion and $409.8 million, respectively, representing increases of 97% and 197%, respectively, as compared to 2000. These dramatic increases were a result of increased demand for drilling services during the first half of the year. To meet the increased demand for additional rigs, during September 2000 we implemented a capital expenditure program to refurbish, recommission and in many cases, upgrade our stacked, domestic drilling fleet. As part of this program, which was terminated in the fourth quarter of 2001, we recommissioned 113 rigs and partially completed 32 rigs. The prolonged strength of the North American natural gas market that continued until the beginning of the third quarter of 2001 resulted in significant increases in both rig years and dayrates. However, this positive trend ended in July 2001 due to the continued steady decline in U.S. natural gas prices. As a result of these lower natural gas prices, the majority of our customers' drilling programs declined and demand for additional rigs in the U.S. Lower 48 drilling market was substantially reduced. We began to experience deterioration in North American gas rig activity during the third quarter of 2001. Nevertheless, U.S. Land Drilling rig years increased to 220.6 years during 2001 from 166.8 years during 2000.

U.S. Land Well-servicing Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $345.8 million and $82.4 million, respectively, representing increases of 29% and 76%, respectively, as compared to 2000. These increases resulted from increased rates per hour and activity resulting from higher natural gas and oil prices. U.S. Land Well-servicing rig hours increased to 1.17 million hours during 2001 from 1.11 million hours during 2000.

U.S. Offshore Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $226.1 million and $55.1 million, respectively, representing an increase of 8% and a decrease of 12%, respectively, as compared to 2000. The increase in revenues during 2001 resulted from higher average dayrates, partially offset by lower rig years. The positive trend of increased revenues ended during July 2001 as a result of the decline in natural gas and oil prices during the third quarter of 2001. Offshore rig years decreased to 28.8 years during 2001 from 30.8 years during 2000.

Canadian Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $86.3 million and $37.5 million, respectively, representing increases of 14% and 25%, respectively, as compared to 2000. These increases resulted from higher average dayrates associated with continued strong demand for natural gas drilling services throughout the Canadian market. During November 2001 we expanded our presence in Canada by completing our acquisition of Command Drilling Corporation, which owned 15 rigs operating in the Canadian Rockies. Rig years in Canada decreased slightly to 20.4 years during 2001 from 21.5 years during 2000.

International Operating revenues and Earnings from unconsolidated affiliates, and adjusted cash flow derived from operating activities totaled $282.4 million and $89.6 million, respectively, representing increases of 55% and 38%, respectively, as compared to 2000. These increases resulted from higher average dayrates and higher rig years in our South American operations, primarily in Colombia, Ecuador and Trinidad, and our African operations, primarily in Algeria. Additionally, effective January 1, 2001, we purchased our partner's 49% interest in our Argentina operation for $4.5 million, and we now own and consolidate 100% of this operation. Prior to January 1, 2001, our interest was accounted for using the equity method of accounting because Nabors' ability to control the entity's operations was restricted by certain substantive participating rights granted to the minority shareholder. International rig years increased to 54.5 years during 2001 from 43.7 years during 2000.

Manufacturing and Logistics Manufacturing and logistics Operating revenues and Earnings from unconsolidated affiliates were $259.3 million during 2001, representing an increase of 47% compared with the prior year. Adjusted cash flow derived from operating activities increased to $105.8 million compared to $63.4 million in the prior year, representing a 67% increase. Increases in this segment resulted primarily from higher average dayrates and utilization in our supply vessel and U.S. trucking operations and from increased top drive sales.

Other Financial Information Our gross margin percentage increased to 38% in 2001 from 32% in 2000, primarily due to higher average dayrates at virtually all of our business units.

General and administrative expenses increased by $29.0 million, or 27%, in 2001 compared to 2000 due to increased rig activity. As a percentage of operating revenues, general and administrative expenses decreased during 2001 as compared to 2000 (6.2% vs. 7.7%) as these expenses were spread over a larger revenue base.

Depreciation and amortization expense increased by $37.5 million, or 25%, in 2001 compared to 2000 due to capital expenditures during 2000 and 2001 and increased rig activity during 2001. 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 approximately $8.6 million for 2001, partially offsetting the increase for the year.

Interest expense increased during 2001 due to higher average debt outstanding, resulting from the issuance of our $825 million zero coupon convertible senior debentures in June 2000 and our $1.381 billion zero coupon convertible senior debentures in February 2001. The issuance of these debentures increased interest expense in 2001 by $30.5 million as compared to 2000. Interest income increased during 2001 due to higher average cash balances resulting from the investment of the proceeds from the issuances of these debentures.

Other income, net increased during 2001, as compared to 2000, due primarily to a gain on extinguishment of debt of $15.3 million recorded during 2001 and a year-over-year increase in gains on long-term assets of $8.5 million, partially offset by a year-over-year decrease in gains on marketable securities and warrants of $17.8 million.

Our effective income tax rate was 36% during 2001 compared to 40% in the prior year. This lower effective tax rate is primarily due to certain transfers of foreign assets formerly owned by our U.S. entities to our foreign companies operating the assets, which generally operate in lower tax jurisdictions.

Liquidity and Capital Resources

Cash Flows

Operating Activities Net cash provided by operating activities totaled $372.4 million during 2002, compared to $695.1 million during 2001. This decrease primarily reflects the decrease in our net income. During 2002 and 2001, in determining net cash provided by operating activities, net income was increased from changes in working capital accounts and for non-cash items such as depreciation and amortization expense, discount amortization on zero coupon debentures and deferred income taxes.

Investing Activities Net cash used for investing activities totaled $629.5 million during 2002, compared to $1.13 billion during 2001. We used cash primarily for purchases of marketable securities, net of sales, capital expenditures and acquisitions of businesses during both 2002 and 2001.

On October 9, 2002, we acquired Ryan pursuant to a plan of arrangement whereby Nabors Exchangeco (Canada) Inc., an indirect wholly-owned Canadian subsidiary of Nabors, acquired all of the issued and outstanding common shares of Ryan in exchange for approximately Cdn. $22.6 million (U.S. $14.2 million) in cash and 380,264 exchangeable shares of Nabors Exchangeco, of which 219,493 exchangeable shares were immediately exchanged for common shares of Nabors in accordance with the instructions of the holders of those shares. The value of the Nabors Exchangeco shares issued totaled Cdn. $18.5 million (U.S. $11.6 million). In addition, we assumed Ryan debt totaling Cdn. $14.5 million (U.S. $9.1 million).

On March 18, 2002, we acquired, for cash, 20.5% of the issued and outstanding shares of Enserco, a Canadian publicly-held corporation, for Cdn. $15.50 per share for a total price of Cdn. $83.2 million (U.S. $52.6 million). On April 26, 2002, Nabors Exchangeco acquired all of the remaining issued and outstanding common shares of Enserco in exchange for approximately Cdn. $100.1 million (U.S. $64.1 million) in cash and 3,549,082 exchangeable shares of Nabors Exchangeco, of which 2,638,526 exchangeable shares were immediately exchanged for Nabors Delaware common stock in accordance with the instructions of the holders of those shares. The value of the Nabors Exchangeco shares issued totaled Cdn. $254.2 million (U.S. $162.8 million). In addition, we assumed Enserco debt totaling Cdn. $33.4 million (U.S. $21.4 million).

Financing Activities Financing activities provided cash totaling $470.4 million during 2002, compared to $432.4 million during 2001. During 2002 cash was provided by our issuance of senior notes totaling $495.9 million and was used primarily for the reduction of long-term borrowings of $30.8 million.

During 2001 cash was primarily provided by the $840.3 million in proceeds from our issuance of $1.381 billion zero coupon convertible senior debentures during February 2001. This was partially offset by $156.0 million of cash used for the reduction of long-term borrowings, primarily attributable to the repurchase of a portion of our zero coupon convertible senior debentures. In addition, we used $248.0 million of cash to repurchase shares of our common stock.

During 2002 we purchased $.6 million face value of our 8.625% senior subordinated notes due April 2008 in the open market at a price of 108%. In addition, we purchased $4.7 million face value of our 6.8% senior notes due April 2004 in the open market at a price of 104%. Upon settlement of these transactions, we paid $5.7 million and recognized a pretax loss of approximately $.2 million, resulting from the repurchases of these notes at prices higher than their carrying value. Additionally, we repaid Cdn. $12.9 million (U.S. $8.3 million) and Cdn. $22.3 million (U.S. $14.3 million) of the debt assumed in the Ryan and Enserco acquisitions, respectively. We also made a $2.5 million scheduled principal payment relating to certain of our medium-term notes.

We had a $200 million unsecured committed revolving credit facility with a syndicate of banks, with an original term of five years, that was scheduled to mature on September 5, 2002. As a result of the corporate reorganization discussed below, we may have failed to comply with a covenant contained in the credit facility agreement and a related $30 million letter of credit facility agreement. At the time of the potential default, there were no outstanding borrowings on the credit facility, and $23 million was outstanding on the related letter of credit facility. The bank provided a waiver on the letter of credit facility and the letter of credit facility has since expired. Because we had cash and marketable securities balances totaling approximately $800 million at the time of the potential default, and because the credit facility was scheduled to mature on September 5, 2002, we terminated the revolving credit facility.

On August 22, 2002, Nabors Holdings 1, ULC, one of our indirect, wholly-owned subsidiaries, issued $225 million aggregate principal amount of 4.875% senior notes due 2009 that are fully and unconditionally guaranteed by Nabors and Nabors Delaware. Concurrently with this offering by Nabors Holdings, Nabors Delaware issued $275 million aggregate principal amount of 5.375% senior notes due 2012, which are fully and unconditionally guaranteed by Nabors. Cash provided by our issuance of these senior notes totaled $495.9 million. The proceeds from our issuance of senior notes were invested in cash and marketable securities. Both issues of senior notes were resold by a placement agent to qualified institutional buyers under Rule 144A of the Securities Act of 1933, as amended. Interest on each issue of senior notes is payable semi-annually on February 15 and August 15, beginning on February 15, 2003. On October 28, 2002, Nabors' registration statements with respect to resales of these senior notes became effective.

On October 21, 2002, we entered into an interest rate swap transaction and purchased a LIBOR range cap and sold a LIBOR floor, in the form of a cashless collar, 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 and to mitigate and manage our exposure to changes in the three-month U.S. dollar LIBOR rate, respectively (see *Quantitative and Qualitative Disclosures About Market Risk* below).

On July 17, 2002, the Board of Directors of Nabors authorized the continuation of the share repurchase program that had begun under Nabors Delaware, and provided that the amount of Nabors common shares authorized for purchase by Nabors going forward be increased to $400 million. Under the Nabors Delaware program, Nabors Delaware had acquired an aggregate of approximately $248.0 million of Nabors Delaware common stock, or 6.2 million shares, during 2001. During the third quarter of 2002 Nabors also acquired, through a subsidiary, 91,000 of its common shares in the open market for $27.30 per share for an aggregate price of $2.5 million. Immediately thereafter these shares were transferred to Nabors. Pursuant to Bermuda law, any shares, when purchased, will be treated as cancelled. Therefore, a repurchase of shares will not have the effect of reducing the amount of Nabors' authorized share capital. Additionally, the Board approved the repurchase of up to $400 million of outstanding debt securities of Nabors and its subsidiaries. These amounts may be increased or decreased at the discretion of the Board, depending upon market conditions and consideration of the best interest of shareholder value. Repurchases may be conducted on the open market, through negotiated transactions or by other means, from time to time, depending upon market conditions and other factors.

Future Cash Requirements

As of December 31, 2002, we had long-term debt, including current maturities, of $2.1 billion and stockholders' equity of $2.2 billion. See table included in "Interest Rate and Marketable Security Price Risk" below for a breakout of the components of long-term debt as of December 31, 2002.

Our $825 million debentures can be put to us on June 20, 2003, June 20, 2008 and June 20, 2013, and our $1.381 billion debentures 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 dates of repurchase. Based on the ability of the debenture holders to exercise their put option on June 20, 2003, the outstanding principal amount on the $825 million debentures of $489.1 million is classified in current liabilities in our consolidated balance sheet as of December 31, 2002.

We may elect to pay all or a portion of the purchase price of the debentures in common stock instead of cash, depending upon our cash balances and cash requirements at that time. We do not presently anticipate using stock to satisfy any such future purchase obligations. In accordance with the indentures with respect to the debt securities, we cannot redeem the $825 million and $1.381 billion debentures before June 20, 2003 and February 5, 2006, respectively, after which time we may redeem all or a portion of the debentures for cash at any time at their accreted value.

The following table summarizes our contractual cash obligations as of December 31, 2002:

	Payments Due by Period				
(In thousands)	Total	2003	2004–2005	2006–2007	Thereafter
Contractual cash obligations:					
Long-term debt:					
Principal	$ 2,167,641	$ 498,701[1]	$ 300,575	$ 826,800[2]	$ 541,565
Interest	259,695	49,414	64,527	58,671	87,083
Operating leases[3]	42,285	16,632	21,045	2,434	2,174
Capital expenditure purchase commitments[3]	42,813	42,813	–	–	–
Time charter commitment[4]	119,080	26,863	53,726	38,491	–
Employment contracts[3]	8,709	2,413	3,540	2,756	–
Total contractual cash obligations	$ 2,640,223	$ 636,836	$ 443,413	$ 929,152	$ 630,822

(1) Includes $494.9 million related to our $825 million zero coupon convertible senior debentures which can to be put to us on June 20, 2003.

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

(3) See Note 15 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.

On February 21, 2003, we issued a Notice of Redemption to the holders of our 8.625% senior subordinated notes due April 2008 for redemption of the notes and all associated guarantees on April 1, 2003. The redemption price will be $1,043.13 per $1,000 principal amount of the notes together with accrued and unpaid interest to the date of redemption. We estimate that the total redemption price will be $45.2 million and will require the recognition of a pretax loss of approximately $.9 million, resulting from the redemption of the notes at prices higher than their carrying value on April 1, 2003. The impact of this post-December 31, 2002 event is not reflected in the table above.

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

	Year Ended December 31,		
(In thousands)	2002	2001	2000
New construction	$ 14,008	$ 17,374	$ 64,512
Enhancement	136,837	398,513	79,251
Acquisitions	329,081	137,355	28,388
Sustaining	102,633	231,683	128,486
	$ 582,559	$ 784,925	$ 300,637

As of December 31, 2002, we had outstanding capital expenditure purchase commitments of approximately $42.8 million, primarily for rig-related sustaining and enhancement capital expenditures. Projected capital expenditures for 2003 for sustaining and known new construction and enhancement projects are expected to total approximately $250 million. We have historically completed a number of acquisitions during down markets 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 stock. Future acquisitions may be paid for using existing cash, borrowings under future lines of credit or issuance of debt or Nabors stock. Such capital expenditures and acquisitions are at our discretion and will depend on our view of market conditions and other factors.

Guarantees

We enter into various agreements providing financial or performance assurance to third parties. Certain of these agreements act 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.

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. We are not able to estimate the potential future maximum payments that might be due under our indemnification guarantees. The following table summarizes the total maximum amount of financial and performance guarantees issued by Nabors:

	Maximum Amount				
(In thousands)	2003	2004	2005	Thereafter	Total
Financial standby letters of credit	$ 34,436	$ –	$ –	$ –	$ 34,436
Guarantee of residual value in lease agreements	542	418	694	–	1,654
Contingent consideration in acquisition	769	769	769	193	2,500
Total	$ 35,747	$ 1,187	$ 1,463	$ 193	$ 38,590

Financial Condition and Sources of Liquidity

As of December 31, 2002, we had cash and cash equivalents and investments in marketable securities totaling $1,330.8 million and working capital of $618.5 million. This compares to cash and cash equivalents and investments in marketable securities totaling $918.6 million and working capital of $700.8 million as of December 31, 2001. In addition, we generate significant cash from operations over the course of a twelve-month period. Our ability to raise money in the public markets is enhanced by our senior unsecured debt ratings as provided by Moody's Investor Service and Standard & Poor's, which are currently "A3" and "A-," respectively.

The year-over-year increase in cash and cash equivalents and investments in marketable securities relates primarily to proceeds received from our August 2002 issuance of senior notes, cash provided by operating activities and cash received from sales of marketable securities classified as available for sale in 2002. This increase was partially offset by cash used for acquisitions, sustaining and enhancement capital expenditures and purchases of marketable securities in 2002. The year-over-year decrease in working capital relates primarily to the current liability classification of $489.1 million principal amount of our $825 million debentures, which can be put to us on June 20, 2003. This decrease was partially offset by the increase in cash and cash equivalents and investments in marketable securities discussed above. Year-over-year declines in accounts receivable, accounts payable and accrued liabilities relate to the overall decrease in revenues and costs in 2002 because of lower activity levels.

Our funded debt to capital ratio was 0.49:1 as of December 31, 2002, compared to 0.46:1 as of December 31, 2001. Our net funded debt to capital ratio was 0.26:1 as of December 31, 2002 and 2001. 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 stockholders' equity. The net funded debt to capital ratio nets cash and cash equivalents, short-term marketable securities and long-term marketable securities 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 6.0:1 as of December 31, 2002, compared to 13.3:1 as of December 31, 2001. The interest coverage ratio is computed by calculating the sum of income before income taxes, interest expense, and depreciation and amortization 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 two letter of credit facilities and a Canadian line of credit facility with various banks as of December 31, 2002. Additionally, we also have letters of credit outstanding under an expired $30 million letter of credit facility. Availability and borrowings under our credit facilities as of December 31, 2002 are as follows:

(In thousands)	
Credit available	$ 79,745
Letters of credit outstanding	(56,267)
Remaining availability	$ 23,478

On December 30, 2002, we filed a shelf registration statement on Form S-3 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. The Commission declared the registration statement effective on January 16, 2003. 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 and planned enhancement capital expenditures and our debt service requirements for the next twelve months, including the planned redemption of our 8.625% senior subordinated notes in April 2003 and the possible redemption of our $825 million zero coupon convertible senior debentures in June 2003.

Corporate Reorganization

Effective June 24, 2002, Nabors, a Bermuda-exempt company, became the successor to Nabors Delaware, a Delaware corporation, following a corporate reorganization. The reorganization was accomplished through the merger of an indirect, newly formed Delaware subsidiary owned by Nabors, into Nabors Delaware. Nabors Delaware was the surviving company in the merger and became a wholly-owned, indirect subsidiary of Nabors.

Upon consummation of the merger, all outstanding shares of Nabors Delaware common stock automatically converted into the right to receive Nabors common shares, with the result that the shareholders of Nabors Delaware on the date of the merger became the shareholders of Nabors. Nabors and its subsidiaries continue to conduct the businesses previously conducted by Nabors Delaware and its subsidiaries. The reorganization was accounted for as a reorganization of entities under common control and accordingly, it did not result in any changes to the consolidated amounts of assets, liabilities and stockholders' equity.

The authorized share capital of Nabors consists of 400 million common shares, par value $.001 per share, and 25 million preferred shares, par value $.001 per share. Common shares issued were 144,964,668 at $.001 par value at December 31, 2002 compared to 144,368,390 at $.10 par value immediately preceding the reorganization. The decrease in par value of common stock from $.10 to $.001 was recorded as an increase to capital in excess of par value and a decrease in common shares in our Consolidated Financial Statements. In conjunction with the reorganization, 6.8 million shares of outstanding treasury stock were retired, as Bermuda law does not recognize the concept of treasury stock. The effect of this retirement reduced common shares by $.7 million, capital in excess of par value by $59.2 million and retained earnings by $192.9 million.

The Board of Nabors Delaware approved the reorganization transaction because international activities are an important part of our current business and we believe that our international operations will continue to grow in the future. Expansion of our international business is an important part of our current business strategy and significant growth opportunities exist in the international marketplace. We believe that reorganizing as a Bermuda company will allow us to implement our business strategy more effectively. In addition, we believe that the reorganization should increase our access to international capital markets and acquisition opportunities, increase our attractiveness to non-U.S. investors, improve global cash management, improve our global tax position and result in a more favorable corporate structure for expansion of our current business.

Several members of the United States Congress have proposed legislation that, if enacted, would have the effect of eliminating the tax benefits of the reorganization. During 2002 the Senate Finance Committee and the House Ways and Means Committee approved legislation that, for United States federal tax purposes, would treat a corporation such as Nabors that reorganizes in a foreign jurisdiction as a domestic corporation and, thus, such foreign corporation would be subject to United States federal income tax. The proposed legislation did not pass during the 2002 session of Congress, but is expected to be reintroduced during 2003. This proposed legislation may have an effective date that is retroactive to a date prior to our reorganization and, if enacted, the expected tax savings from the reorganization will not be realized.

In light of such events and if and when any such legislation is enacted, we will consider the effects of the legislation and will evaluate all strategic alternatives that may be appropriate.

Other Matters

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 Exchange 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 must recognize that events and actual results could turn out to be significantly different from our expectations.

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 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 Item I, Part I, "Risk Factors."

Recent Accounting Pronouncements

SFAS No. 142, "Goodwill and Other Intangible Assets," addresses the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: (1) goodwill and intangible assets with indefinite lives no longer will be amortized; (2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and (3) the amortization period for those intangible assets with finite lives no longer will be limited to 40 years. The effect of no longer amortizing goodwill would have increased net income by approximately $4.6 million ($.02 per diluted share) and $3.5 million ($.02 per diluted share) for the years ended December 31, 2001 and 2000, respectively.

We adopted SFAS 142 effective January 1, 2002, and accordingly we no longer record goodwill amortization expense. During the second quarter of 2002 we performed our initial goodwill impairment assessment as required. As part of that assessment, we determined that our 11 business units, as of January 1, 2002, represented our reporting units as defined by SFAS 142. We determined the aggregate carrying values and fair values of all such reporting units, which were measured as of the January 1, 2002 adoption date. We calculated the fair value of each reporting unit based on discounted cash flows and determined there was no goodwill impairment.

We adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," effective January 1, 2002. This statement addresses financial accounting and reporting for the impairment or disposal of long-lived assets. Upon adoption, this new accounting pronouncement had no impact on our reported results of operations or financial position.

We adopted SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," effective April 1, 2002. Due to the nature of our business, Financial Accounting Standards Board (FASB) 44, 64 and Amendment of FASB 13 are not applicable. SFAS 145 eliminates SFAS No. 4, "Reporting Gains and Losses from Extinguishment of Debt" and states that gains and losses from the extinguishment of debt should be classified as extraordinary items only if they meet the criteria in Accounting Principles Board (APB) Opinion No. 30, "Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions." APB 30 defines extraordinary items as events and transactions that are distinguished by their unusual nature and by the infrequency of their occurrence. Accordingly, we no longer classify gains and losses from extinguishment of debt that are usual and frequent as extraordinary items, and we reclassified to other income all similar debt extinguishment items that had been reported as extraordinary items in prior accounting periods. In conjunction with adopting SFAS 145 we reclassified, for fiscal years 2002, 2001 and 2000, the following extraordinary (losses) gains to other income with the related income tax component reclassified to income tax expense, respectively: $(.13 million), net of tax benefit of $.08 million; $9.6 million, net of taxes of $5.7 million and $1.9 million, net of taxes of $1.1 million. These reclassifications had no impact on net income.

In July 2002 the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs that are associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. This statement is effective for fiscal years beginning after December 31, 2002 and will impact any exit or disposal activities initiated after January 1, 2003. This statement does not currently impact Nabors.

We adopted Emerging Issues Task Force (EITF) No. 01-14, "Income Statement Characterization of Reimbursements Received for Out-of-Pocket Expenses Incurred," in the second quarter of 2002. Previously, we recognized reimbursements received as a reduction to the related direct costs. EITF 01-14 requires that reimbursements received be included in operating revenues and out-of-pocket expenses be included in direct costs. Accordingly, reimbursements received from our customers have been reclassified to revenues for all periods presented. The effect of adopting EITF 01-14 resulted in the following reclassifications to our annual results for 2001 and 2000: operating revenues and direct costs were increased from previously reported amounts by $70.0 million and $50.3 million, respectively. These reclassifications had no impact on net income.

In November 2002 the 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 a third party. The initial recognition and measurement provisions of FIN 45 should be applied on a prospective basis for guarantees issued or modified after December 31, 2002. The disclosure requirements of FIN 45 are effective for financial statements of both interim and annual periods ending after December 15, 2002. The adoption of the recognition and measurement provisions of FIN 45 is not expected to have a material impact on our consolidated financial position, results of operations or cash flows. The disclosures required by FIN 45 are included in *Liquidity and Capital Resources* and in Note 15 to our accompanying consolidated financial statements.

On December 31, 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – an Amendment of FAS 123." This statement amends FASB Statement No. 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation. It also amends the disclosure provisions of that statement to require prominent disclosure about the effects on reported net income of an entity's accounting policy decisions with respect to stock-based employee compensation. This statement is effective for financial statements for fiscal years ending after December 15, 2002. SFAS 148 does not change the provisions of SFAS 123 that permit entities to continue to apply the intrinsic value method of APB No. 25, "Accounting for Stock Issued to Employees." However, those companies that continue to account for awards of stock-based employee compensation under the intrinsic value method of APB 25 are required to disclose certain information using a tabular presentation mandated by SFAS 148. At the present time, we plan to continue accounting for stock-based compensation using the intrinsic value method under APB 25 and have presented the disclosures required by SFAS 148 in Note 3 to our accompanying consolidated financial statements.

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. The consolidation requirements of FIN 46 apply immediately to VIEs created after January 31, 2003. For VIEs created at an earlier date, the consolidation requirements apply in the first fiscal year or interim period beginning after June 15, 2003. Certain disclosure requirements apply in all financial statements issued after January 31, 2003, regardless of when the VIE was established. Based on current information, Nabors believes it has no material interests in VIEs that will require disclosure or consolidation under FIN 46.

Related Party Transactions

Pursuant to his employment agreement, we provided an unsecured, non-interest bearing loan of approximately $2.9 million to Nabors' 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, President and Chief Operating Officer, its former Vice Chairman, 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 sheet. We have made premium payments to date totaling $12.8 million related to these policies. The cash surrender value of these policies of approximately $8.7 million is included in other long-term assets in our consolidated balance sheet as of December 31, 2002.

Under the recently enacted Sarbanes-Oxley Act of 2002, the future payment of premiums by Nabors under these agreements may be deemed to be prohibited loans by us to these individuals. We have paid no premiums related to these agreements since the adoption of the Sarbanes-Oxley Act, and we have postponed premium payments related to these agreements pending clarification of the Act's application to these insurance agreements. We will monitor developments and intend to take appropriate action to ensure that these agreements do not violate applicable law.

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 $65.7 million, $26.9 million and $27.6 million in 2002, 2001 and 2000, respectively. Expenses from these business transactions totaled $32.1 million, $4.8 million and $4.9 million in 2002, 2001 and 2000, respectively. Additionally, we had amounts receivable from these affiliated entities of $53.3 million and $24.4 million as of December 31, 2002 and 2001, respectively. We had accounts payable to these affiliated entities of $1.1 million and $3.3 million as of December 31, 2002 and 2001, respectively.

Critical Accounting Policies

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.

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 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 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 — 15 to 25 years; marine transportation and supply vessels — 15 to 25 years; oilfield hauling and mobile equipment and other machinery and equipment — 3 to 10 years). Amortization of capitalized leases is included in depreciation and amortization expense. 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.

We review our assets for impairment when events or changes in circumstances indicate that the net book values of equipment may not be recovered over their remaining service lives. 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. Impairment charges are recorded using discounted cash flows which require the estimation of dayrates and utilization, and such estimates can change based on market conditions, technological advances in the industry or changes in regulations governing the industry. There were no impairment charges related to assets held for use recorded by Nabors in 2002, 2001 and 2000. In 2002 we reclassified four supply vessels to available-for-sale as we intend to sell these vessels in 2003. Accordingly, we reduced the carrying values of these assets to levels approximating their respective fair values, resulting in a charge to other income of $3.7 million in 2002.

Self-Insurance Accruals We are self-insured for certain losses relating to workers' compensation, employers' liability, general liability, automobile liability and property damage. Given the recent tightening in the insurance market, effective April 1, 2002, in connection with our insurance renewal, our self-insurance levels have significantly increased. As a result, our self-insurance retentions for losses relating to workers' compensation, general liability and property damage have increased significantly. Effective for the period from April 1, 2002 to March 31, 2003, our exposure (that is, our deductible) per occurrence is $1.0 million for workers' compensation and employers' liability, $2.0 million for marine employers' liability (Jones Act) and $5.0 million for general liability losses. Our self-insurance for automobile liability loss is $0.5 million per occurrence. We maintain actuarially supported accruals on our consolidated balance sheet to cover the self-insurance retentions.

We are self-insured for certain other losses relating to rig, equipment, property, business interruption and political, war and terrorism risks. Effective April 1, 2002, our per occurrence self-insured retentions are $10.0 million for rig physical damage and business interruption. However, our rigs, equipment and property in Canada and Saudi Arabia are subject to $1.0 million self-insurance retentions. As a result, with the exception of Canada and Saudi Arabia, we are self-insured for rigs with replacement values less than $10.0 million. If a Nabors rig with a net book value of less than $10.0 million was destroyed, we would record a loss equal to its net book value in the period in which the loss event occurred. In previous years, we had physical damage insurance for essentially all of our rigs, with a substantially lower deductible of $.25 million per occurrence. Thus, historically we have not recorded significant losses in our financial statements related to the destruction of one of our rigs. We have purchased stop-loss coverage in order to limit our aggregate exposure to certain physical damage claims for insured rigs (that is, those rigs with replacement values in excess of $10.0 million). The effect of this coverage is that our maximum physical damage loss on insured rigs would be $20.0 million plus $1.0 million per occurrence.

Political risk, war and terrorism insurance is procured for our operations in Mexico, the Caribbean, South America, Africa, the Middle East and Asia. Through December 31, 2002, political and war risk losses were subject to $10.0 million per occurrence deductibles while terrorism was subject to a $1.0 million per occurrence deductible. On January 1, 2003, we purchased additional insurance to reduce these self-insurance retentions to $0.25 million per occurrence, except for Colombia which remains at $10.0 million and $1.0 million for political risk and terrorism, respectively. There is no assurance that such coverage will adequately protect Nabors against liability from all potential consequences.

Revenue Recognition Revenues and costs on daywork contracts are recognized daily as the work progresses, and revenues and costs applicable to footage and turnkey contracts are recognized when the well is completed (completed contract method). 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 those top drives and instrumentation systems we manufacture for third parties when the earnings process is complete. This generally occurs when products have been shipped or factory acceptance testing on our products has been completed and the products are made available to our customers in accordance with the terms of the agreement, 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.

In accordance with EITF 00-14, we recognize reimbursements received for out-of-pocket expenses incurred as revenues and account for out-of-pocket expenses as direct costs.

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. federal income tax purposes, we have net operating loss carryforwards of approximately $249.5 million that, if not utilized, will expire from 2003 to 2023. The net operating loss carryforwards for alternative minimum tax purposes are approximately $145.6 million. There are alternative minimum tax credit carryforwards of $22.8 million available to offset future regular tax liabilities.

We do not provide U.S. income and foreign withholding taxes on unremitted earnings of our international subsidiaries, as these earnings are considered permanently reinvested. Unremitted earnings totaled approximately $377.2 million and $212.0 million as of December 31, 2002 and 2001, respectively. It is not practicable to estimate the amount of deferred income taxes associated with these unremitted earnings. Deferred taxes have been provided for foreign taxes related to assets which are expected to reside in certain foreign locations long enough to give rise to future tax consequences.

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

Allowance for doubtful accounts 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 or significant changes in the prices of natural gas or oil.

Depreciation and amortization In order to depreciate and amortize our property, plant and equipment and our intangible assets with definite 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.

Tax estimates 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 such loss carryforwards, or whether or not such loss carryforwards will be available in the future.

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 claims could differ significantly from estimated amounts. We maintain actuarially supported accruals on our consolidated balance sheets to cover self-insurance retentions.

Fair values 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. 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 a reporting unit level. Therefore, considerable judgment, similar to that described above in connection with our estimation of the fair value of an acquired company, will be required to assess goodwill and certain intangible assets for impairment.

For additional information on our accounting policies, see Note 3 to our accompanying consolidated financial statements.

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 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.

We have an operation in Argentina that is not significant to our overall profitability. Our Argentina operation contributed approximately 1% of our revenues and adjusted income derived from operating activities in 2002. As a result of the financial crisis in Argentina, the Argentine government allowed their currency, the peso, to float beginning in January 2002. The peso, which had been pegged to the U.S. dollar for several years, has devalued approximately 68%. Changes in the valuation of the peso in 2002 resulted in a translation gain of approximately $1.1 million, recorded to accumulated other comprehensive income in our consolidated balance sheet.

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, 2002 would result in a $9.2 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 and 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 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 Security Price Risk Our financial instruments that are potentially sensitive to changes in interest rates include our $825 million and $1.381 billion zero coupon convertible senior debentures, our 6.8%, 4.875% and 5.375% senior notes, our 8.625% senior subordinated notes, our interest rate swap and range cap and floor transactions, and our investments in debt securities, including corporate, asset-backed, U.S. Government, Government agencies, foreign government and mortgage-backed debt 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.

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. The purpose of this transaction was to convert future interest due on $200 million of the senior notes to a lower variable rate in an attempt to realize savings on our future interest payments. We have designated this swap agreement as a fair value hedge. The swap agreement has a notional amount of $200 million and matures in August 2012 to match the maturity of the senior notes. Under the agreement, we pay on a quarterly basis a floating rate based on a three-month U.S. dollar LIBOR rate, plus a spread of 62.625 basis points, and receive a fixed rate of interest of 5.375% semi-annually. During 2002 we recorded interest savings related to this interest rate swap of $1.2 million which served to reduce interest expense. The change in cumulative fair value of this derivative instrument resulted in the recording of a derivative asset, included in other long-term assets, of $10.1 million as of December 31, 2002. The carrying value of our 5.375% senior notes was increased by the same amount.

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 which we had executed the interest rate swap. This transaction is intended to mitigate and manage our exposure to changes in the three-month U.S. dollar LIBOR rate and does not qualify for hedge accounting treatment under SFAS 133. Any change in the cumulative fair value of the range cap and the floor will be reflected as a gain or loss in our consolidated statement of income. The range cap and the floor are effective August 15, 2003 and expire on August 15, 2012. The range cap will be triggered when the three-month U.S. dollar LIBOR rate is at or above 4.50%, and below 6.50%, such that the counterparty will pay us any difference between the actual LIBOR rate and the 4.50% strike rate on a notional amount of $200 million. No payment will be due to us if the three-month U.S. dollar LIBOR rate is below 4.50% or at or above 6.50%. The floor is triggered when the three-month U.S. dollar LIBOR rate is at or below 2.665% such that we will pay the counterparty any difference between the actual LIBOR rate and the 2.665% floor rate on a notional amount of $200 million. We recorded a loss of $3.8 million during 2002 related to the change in cumulative fair value of this derivative instrument. This loss is included in other income in our consolidated statement of income for the year ended December 31, 2002 and has been accrued in other long-term liabilities in our consolidated balance sheet as of December 31, 2002.

A hypothetical 10% adverse shift in quoted interest rates would decrease the fair values of our interest rate swap, and range cap and floor by approximately $6.8 million and $1.0 million, respectively.

On July 25, 2002, we entered into an interest rate hedge transaction with a third-party financial institution to manage and mitigate interest rate risk exposure relative to our August 2002 debt financing. Under the agreement, we agreed to receive (pay) cash from (to) the counterparty based on the difference between 4.43% and the ten-year Treasury rate on August 23, 2002, assuming a $100.0 million notional amount with semi-annual interest payments over a ten-year maturity. We accounted for this transaction as a cash flow hedge. During August 2002 we paid approximately $1.5 million related to the termination of this agreement. This payment was recorded as a reduction to accumulated other comprehensive income in our consolidated balance sheet and will be amortized into earnings as additional interest expense, using the effective interest method, over the term of the 5.375% senior notes due 2012.

On March 26, 2002, in anticipation of closing the Enserco acquisition, we entered into two foreign exchange contracts with a total notional value of Cdn. $115.9 million and maturity dates of April 29, 2002. Additionally, on April 9, 2002, we entered into a third foreign exchange contract with a notional value of Cdn. $50.0 million maturing April 29, 2002. The notional amounts of these contracts were used to fund the cash portion of the Enserco acquisition purchase price. The notional amounts of these contracts represented the amount of foreign currency purchased at maturity and did not represent our exposure under these contracts. Although such contracts served as an economic hedge against our foreign currency risk related to the cash portion of the acquisition cost, these contracts did not qualify for hedge accounting treatment under SFAS 133. We recognized a gain on these foreign exchange contracts of approximately U.S. $1.78 million included in other income in our consolidated statement of income for the year ended December 31, 2002.

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

	December 31, 2002		
(In thousands, except interest rates)	Effective Interest Rate	Carrying Value	Fair Value
4.875% senior notes due August 2009	4.952%	$ 223,234	$ 231,854
5.375% senior notes due August 2012	4.194%(1)	282,901(2)	293,478(2)
$825 million zero coupon convertible senior debentures due June 2020	2.5%	489,126	494,081
$1.381 billion zero coupon convertible senior debentures due February 2021	2.5%	765,549	756,733
6.8% senior notes due April 2004	6.8%	295,237	310,068
Other long-term debt	7.8%	9,101	9,101
8.625% senior subordinated notes due April 2008	8.415%	42,493	43,930
		$ 2,107,641	$ 2,139,245

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

(2) Includes $10.1 million related to the fair value of the interest rate swap.

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 as follows:

	December 31, 2002		
(In thousands, except interest rates and weighted average life)	Fair Value	Interest Rates	Weighted Average Life (Years)
Cash and cash equivalents	$ 414,051	N/A	N/A
Marketable equity securities:			
Trading	4,260	N/A	N/A
Available-for-sale	45,574	N/A	N/A
Marketable debt securities:			
Commercial paper and CDs	76,548	1.33%–2.51%	.1
Corporate debt securities	204,084	1.37%–7.88%	.5
U.S. Government debt securities	42,675	3.00%–5.87%	1.7
Government agencies debt securities	386,096	1.24%–5.63%	.7
Foreign government debt securities	15,213	7.12%–8.80%	.2
Mortgage-CMO debt securities	355	7.50%	.6
Asset-backed debt securities	141,943	2.76%–7.75%	.9
	$ 1,330,799		

Our investments in marketable debt securities listed in the above table 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 would decrease the fair value of our trading securities and available-for-sale securities by $.4 million and $91.2 million, respectively.

Report of Independent Accountants

{Nabors Industries Ltd. and Subsidiaries}

To the Stockholders 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 stockholders' equity present fairly, in all material respects, the financial position of Nabors Industries Ltd. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, 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 3 to the consolidated financial statements, Nabors Industries Ltd. changed its method of accounting for goodwill effective January 1, 2002.

PricewaterhouseCoopers LLP

Houston, Texas
January 29, 2003,
except for Note 21, as to which the date is
March 18, 2003