NABORS INDUSTRIES LTD
Form 10-K
March 02, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

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

For the transition period from ____________________ to ____________________

Commission File Number 000-49887
NABORS INDUSTRIES LTD.
(Exact name of registrant as specified in its charter)

Bermuda	**980363970**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
Mintflower Place **8 Par-La-Ville Road** **Hamilton, HM08** **Bermuda**	**N/A**
(Address of principal executive offices)	(Zip Code)

(441) 292-1510
(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Name of each exchange on which registered
Common shares, $.001 par value per share	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Securities Exchange Act of 1934:
None.

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

YES þ NO o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

YES o NO þ

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES þ NO o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

YES o NO þ

The aggregate market value of the 243,395,864 common shares, par value $.001 per share, held by non-affiliates of the registrant, based upon the closing price of our common shares as of the last business day of our most recently completed second fiscal quarter, June 30, 2008, of $49.23 per share as reported on the New York Stock Exchange, was $11,982,378,385. Common shares held by each officer and director and by each person who owns 5% or more of the outstanding common shares have been excluded in that such persons may be deemed affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

The number of common shares, par value $.001 per share, outstanding as of February 23, 2009 was 282,930,433. In addition, our subsidiary, Nabors Exchangeco (Canada) Inc., had 104,520 exchangeable shares outstanding as of February 23, 2009 that are exchangeable for Nabors common shares on a one-for-one basis, and have essentially identical rights as Nabors Industries Ltd. common shares, including but not limited to voting rights and the right to receive dividends, if any.

DOCUMENTS INCORPORATED BY REFERENCE (to the extent indicated herein)

Specified portions of the 2009 Notice of Annual Meeting of Shareholders and the definitive Proxy Statement to be distributed in connection with the 2009 annual meeting of shareholders (Part III).

NABORS INDUSTRIES LTD.
Form 10-K Annual Report
For the Fiscal Year Ended December 31, 2008
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Our internet address is www.nabors.com. We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (the Exchange Act) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (the SEC). In addition, a glossary of drilling terms used in this document and documents relating to our corporate governance (such as committee charters, governance guidelines and other internal policies) can be found on our website. The SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

FORWARD-LOOKING STATEMENTS

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

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

- fluctuations in worldwide prices of and demand for natural gas and oil;
- fluctuations in levels of natural gas and oil exploration and development activities;
- fluctuations in the demand for our services;
- the existence of competitors, technological changes and developments in the oilfield services industry;
- the existence of operating risks inherent in the oilfield services industry;
- the existence of regulatory and legislative uncertainties;
- the possibility of changes in tax laws;
- the possibility of political instability, war or acts of terrorism in any of the countries in which we do business; and
- general economic conditions including the capital and credit markets.

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 see Part I, Item 1A. Risk Factors.

Unless the context requires otherwise, references in this Annual Report on Form 10-K to we, us, our, Company, Nabors means Nabors Industries Ltd. and, where the context requires, includes our subsidiaries.

PART I

ITEM 1. BUSINESS

Introduction

Nabors is the largest land drilling contractor in the world, with approximately 528 actively marketed land drilling rigs. We conduct oil, gas and geothermal land drilling operations in the U.S. Lower 48 states, Alaska, Canada, South America, Mexico, the Caribbean, the Middle East, the Far East, Russia and Africa. We are also one of the largest land well-servicing and workover contractors in the

United States and Canada. We actively market approximately 592 land workover and well-servicing rigs in the United States, primarily in the southwestern and western United States, and actively market approximately 171 land workover and well-servicing rigs in Canada. Nabors is a leading provider of offshore platform workover and drilling rigs, and actively markets 37 platform rigs, 13 jack-up units and 3 barge rigs in the United States and multiple international markets. These rigs provide well-servicing, workover and drilling services. We have a 51% ownership interest in a joint venture in Saudi Arabia, which owns and actively markets 9 rigs in addition to the rigs we lease to the joint venture. We also offer a wide range of ancillary well-site services, including engineering, transportation, construction, maintenance, well logging, directional drilling, rig instrumentation, data collection and other support services in selected domestic and international markets. We provide logistics services for onshore drilling in Canada using helicopters and fixed-winged aircraft. We manufacture and lease or sell top drives for a broad range of drilling applications, directional drilling systems, rig instrumentation and data collection equipment, pipeline handling equipment and rig reporting software. We also invest in oil and gas exploration, development and production activities and have 49-50% ownership interests in the U.S., Canada and International areas.

Nabors was formed as a Bermuda-exempt company on December 11, 2001. Through predecessors and acquired entities, Nabors has been continuously operating in the drilling sector since the early 1900s. Our principal executive offices are located at Mintflower Place, 8 Par-La-Ville Road, Hamilton, HM08, Bermuda. Our phone number at our principal executive offices is (441) 292-1510.

Our Fleet of Rigs

Land Rigs. A land-based drilling rig generally consists of engines, a drawworks, a mast (or derrick), pumps to circulate the drilling fluid (mud) under various pressures, blowout preventers, drill string and related equipment. The engines power the different pieces of equipment, including a rotary table or top drive that turns the drill string, causing the drill bit to bore through the subsurface rock layers. Rock cuttings are carried to the surface by the circulating drilling fluid. The intended well depth, bore hole diameter and drilling site conditions are the principal factors that determine the size and type of rig most suitable for a particular drilling job.

A land-based workover or well-servicing rig consists of a mobile carrier, engine, drawworks and a mast. The mobile workover or well-servicing rig is specially designed for periodic maintenance as well as major repairs and modifications of oil and gas wells for which service is required to maximize the productive life of such wells. Workovers may be required to remedy failures, modify well depth and formation penetration to capture hydrocarbons from alternative formations, clean out and recomplete a well when production has declined, repair leaks or convert a depleted well to an injection well for secondary or enhanced recovery projects. The primary function of a workover or well-servicing rig is to act as a hoist so that pipe, sucker rods and down-hole equipment can be run into and out of a well. Because of size and cost considerations, well-servicing and workover rigs are used for these operations rather than the larger drilling rigs. Land-based drilling rigs are moved between well sites and between geographic areas of operations by using our fleet of cranes, loaders and transport vehicles or those from a third-party service vendor. Well-servicing rigs are generally self-propelled units and heavier capacity workover rigs are either self-propelled or trailer mounted and include auxiliary equipment, which is either transported on trailers or moved with trucks.

Platform Rigs. Platform rigs provide offshore workover, drilling and re-entry services. Our platform rigs have drilling and/or well-servicing or workover equipment and machinery arranged in modular packages that are transported to, and assembled and installed on, fixed offshore platforms owned by the customer. Fixed offshore platforms are steel tower-like structures that either stand on the ocean floor or are moored floating structures. The top portion, or platform, sits above the water level and provides the foundation upon which the platform rig is placed.

Jack-up Rigs. Jack-up rigs are mobile, self-elevating drilling and workover platforms equipped with legs that can be lowered to the ocean floor until a foundation is established to support the hull, which contains the drilling and/or workover equipment, jacking system, crew quarters, loading and unloading facilities, storage areas for bulk and liquid materials, helicopter landing deck and other related equipment. The rig legs may operate independently or have a mat attached to the lower portion of the legs in order to provide a more stable foundation in soft bottom areas. Many of our jack-up rigs are of cantilever design a feature that permits the drilling platform to be extended out from the hull, allowing it to perform drilling or workover operations over adjacent, fixed platforms. Nabors shallow workover jack-up rigs generally are subject to a maximum water depth of approximately 125 feet, while some of our jack-up rigs may drill in water depths as shallow as 13 feet. Nabors also has deeper water depth capacity jack-up rigs that are capable of drilling at depths between eight feet and 150 to 250 feet. The water depth limit of a particular rig is determined by the length of the rig s legs and the operating environment. Moving a rig from one drill site to another involves lowering the hull down into the water until it is afloat and then jacking up its legs with the hull floating. The rig is then towed to the new drilling site.

Inland Barge Rigs. One of Nabors barge rigs is a full-size drilling unit. Nabors also owns two workover inland barge rigs. These barges are designed to perform plugging and abandonment, well service or workover services in shallow inland, coastal or offshore waters. Our barge rigs can operate at depths between three and 20 feet.

Additional information regarding the geographic markets in which we operate and our business segments can be found in Note 20 in Part II, Item 8. Financial Statements and Supplementary Data.

Customers: Types of Drilling Contracts

Our customers include major oil and gas companies, foreign national oil and gas companies and independent oil and gas companies. No customer accounted for greater than 10% of consolidated revenues in 2008 or in 2007.

On land in the U.S. Lower 48 states and Canada, we have historically been contracted on a single-well basis, with extensions subject to mutual agreement on pricing and other significant terms. Beginning in late 2004, as a result of increasing demand for drilling services, our customers started entering into longer term contracts with durations ranging from one to three years. Under these contracts, our rigs are committed to one customer over that term. Increasingly, these contracts are being signed for three-year terms for newly constructed rigs. Contracts relating to offshore drilling and land drilling in Alaska and international markets generally provide for longer terms, usually from one to five years. Offshore workover projects are often on a single-well basis. We generally are awarded drilling contracts through competitive bidding, although we occasionally enter into contracts by direct negotiation. Most of our single-well contracts are subject to termination by the customer on short notice, but some can be firm for a number of wells or a period of time, and may provide for early termination compensation in certain circumstances. The contract terms and rates may differ depending on a variety of factors, including competitive conditions, the geographical area, the geological formation to be drilled, the equipment and services to be supplied, the on-site drilling conditions and the anticipated duration of the work to be performed.

In recent years, all of our drilling contracts have been daywork contracts. A daywork contract generally provides for a basic rate per day when drilling (the dayrate for us providing a rig and crew) and for lower rates when the rig is moving, or when drilling operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other conditions beyond our control. In addition, daywork contracts may provide for a lump sum fee for the mobilization and demobilization of the rig, which in most cases approximates our incurred costs. A daywork contract differs from a footage contract (in which the drilling contractor is paid on the basis of a rate per foot drilled) and a turnkey contract (in which the drilling contractor is paid for drilling a well to a specified depth for a fixed price).

Well-Servicing and Workover Services

Although some wells in the United States flow oil to the surface without mechanical assistance, most are in mature production areas that require pumping or some other form of artificial lift. Pumping oil wells characteristically require more maintenance than flowing wells because of the operation of the mechanical pumping equipment installed.

Well-Servicing/Maintenance Services. We provide maintenance services on the mechanical apparatus used to pump or lift oil from producing wells. These services include, among other things, repairing and replacing pumps, sucker rods and tubing. We provide the rigs, equipment and crews for these tasks, which are performed on both oil and natural gas wells, but which are more commonly required on oil wells. Maintenance services typically take less than 48 hours to complete. Well-servicing rigs generally are provided to customers on a call-out basis. We are paid an hourly rate and work typically is performed five days a week during daylight hours.

Workover Services. Producing oil and natural gas wells occasionally require major repairs or modifications, called workovers. Workovers normally are carried out with a well-servicing rig that includes additional specialized accessory equipment, which may include rotary drilling equipment, mud pumps, mud tanks and blowout preventers. A workover may last anywhere from a few days to several weeks. We are paid an hourly rate and work is generally performed seven days a week, 24 hours a day.

Completion Services. The kinds of activities necessary to carry out a workover operation are essentially the same as those that are required to complete a well when it is first drilled. The completion process may involve selectively perforating the well casing at the depth of discrete producing zones, stimulating and testing these zones and installing down-hole equipment. The completion process may take a few days to several weeks. We are paid an hourly rate and work is generally performed seven days a week, 24 hours a day.

Production and Other Specialized Services. We also can provide other specialized services, including onsite temporary fluid-storage facilities, the provision, removal and disposal of specialized fluids used during certain completion and workover operations, and the removal and disposal of salt water that often is produced in conjunction with the production of oil and natural gas. We also provide plugging services for wells from which the oil and natural gas has been depleted or further production has become uneconomical. We are paid an hourly or a per unit rate, as applicable, for these services.

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Oil and Gas Investments

Through our wholly owned Ramshorn business unit, Nabors makes investments in oil and gas exploration, development and production operations in the United States, Canada and internationally. In addition in late 2006, we entered into an agreement with First Reserve Corporation to form select joint ventures to invest in oil and gas exploration opportunities worldwide. During 2007, three joint ventures were formed for operations in the United States, Canada and international areas. We hold 49.7% ownership interests in the U.S. and international entities and a 50% ownership interest in the Canadian entity and account for these investments using the equity method of accounting. Each joint venture pursues development and exploration projects with both existing customers of ours and with other operators in a variety of forms including operated and non-operated working interests, joint ventures, farm-outs and acquisitions. The U.S. joint venture business is focused on the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids in Texas, Montana, Utah and North Dakota. Outside of the United States, our joint venture entities own or have interests in the Alberta and British Columbia Provinces of Canada and internationally in Colombia.

Additional information about recent activities for this segment can be found in Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Oil and Gas.

Other Services

Canrig Drilling Technology Ltd., our drilling technologies and well services subsidiary, manufactures top drives, which are installed on both onshore and offshore drilling rigs. Our top drives are marketed throughout the world. During the last three years, approximately 53% of our top drive sales were made to other Nabors companies. We also rent top drives and provide top drive installation, repair and maintenance services to our customers. We also offer rig instrumentation equipment, including sensors, proprietary RIGWATCH® software and computerized equipment that monitors the real-time performance of a rig. In addition, we specialize in daily reporting software for drilling operations, making this data available through the internet on the website www.mywells.com. We also provide mudlogging services. Canrig Drilling Technology Canada Ltd., one of our Canadian subsidiaries, manufactures catwalks and wrenches which are installed on both onshore and offshore drilling rigs. During the 31 months of operations since acquisition, approximately 62% of the equipment sales were made to other Nabors companies. Ryan Energy Technologies, Inc., another one of our subsidiaries, manufactures and sells directional drilling and rig instrumentation and data collection services to oil and gas exploration and service companies. Nabors has a 50% interest in Peak Oilfield Service Company, a general partnership with a subsidiary of Cook Inlet Region, Inc., a leading Alaskan native corporation. Peak Oilfield Service Company provides heavy equipment to move drilling rigs, water, other fluids and construction materials, primarily on Alaska s North Slope and in the Cook Inlet region. The partnership also provides construction and maintenance for ice roads, pads, facilities, equipment, drill sites and pipelines. Nabors also has a 50% membership interest in Alaska Interstate Construction, L.L.C., a limited liability company whose other member is a subsidiary of Cook Inlet Region, Inc. Alaska Interstate Construction is a general contractor involved in the construction of roads, bridges, dams, drill sites and other facility sites, as well as providing mining support in Alaska. Revenues are derived from services to companies engaged in mining and public works. Our subsidiary, Peak USA Energy Services, Ltd., provides hauling and maintenance services for customers in the U.S. Lower 48 states. Nabors Blue Sky Ltd. leases aircraft used for logistics services for onshore drilling in Canada using helicopters and fixed-winged aircraft.

Our Employees

As of December 31, 2008, Nabors employed approximately 26,912 persons, of whom approximately 3,920 were employed by unconsolidated affiliates. We believe our relationship with our employees generally is good.

Certain rig employees in Argentina and Australia are represented by collective bargaining units.

Seasonality

Our Canadian and Alaskan drilling and workover operations are subject to seasonal variations as a result of weather conditions and generally experience reduced levels of activity and financial results during the second calendar quarter of each year. Seasonality does not have a material impact on the remaining portions of our business. Our overall financial results reflect the seasonal variations experienced in our Canadian and Alaskan operations.

Research and Development

Research and development constitutes a growing part of our overall business. The effective use of technology is critical to the maintenance of our competitive position within the drilling industry. As a result of the importance of technology to our business, we expect to continue to develop technology internally or to acquire technology through strategic acquisitions.

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Industry/Competitive Conditions

To a large degree, Nabors businesses depend on the level of capital 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 by our customers and could also materially affect our financial position, results of operations and cash flows. See Part I, Item 1A. Risk Factors Fluctuations in oil and natural gas prices could adversely affect drilling activity and our revenues, cash flows and profitability.

Our industry remains competitive. Historically, the number of rigs has exceeded demand in many of our markets. From 2005 through most of 2008, as a result of improved demand for drilling services driven by a sustained increase in the level of commodity prices, supply of and demand for land drilling services have been in balance in the United States and international markets, with demand actually exceeding supply in some of our markets. This economic reality resulted in an increase in rates being charged for rigs across our North American, Offshore and International markets. Furthermore, the dramatic increase in rates along with our domestic customers willingness to enter into firm three-year commitments has resulted in our building of new rigs in significant quantities for the first time in over 20 years. Internationally, we compete directly with various contractors in areas where we operate. We believe that our international markets will continue to be competitive for the foreseeable future. However, as many existing rigs can be readily moved from one region to another in response to changes in levels of activity and many of the total available contracts are currently awarded on a bid basis, competition based on price for both existing and new rigs still exists across all of our markets.

In all of our geographic market areas, we believe price and availability and condition of equipment are the most significant factors in determining which drilling contractor is awarded a job. Other factors include the availability of trained personnel possessing the required specialized skills; the overall quality of service and safety record; and domestically, the ability to offer ancillary services. Increasingly, the ability to deliver rigs within certain timeframes is becoming a competitive factor. In international markets, experience in operating in certain environments and customer alliances, also have been factors in the selection of Nabors.

Certain competitors are present in more than one of Nabors operating regions, although no one competitor operates in all of these areas. In the U.S. Lower 48 states, we compete with Helmerich and Payne, Inc. and Patterson-UTI Energy, Inc. and there are several hundred other competitors with national, regional or local rig operations. In domestic land workover and well-servicing, we compete with Basic Energy Services, Inc., Key Energy Services, Inc., Complete Energy Services and with numerous other competitors having smaller regional or local rig operations. In Canada and Offshore, Nabors competes with many firms of varying size, several of which have more significant operations in those areas than Nabors. Internationally, Nabors competes directly with various contractors at each location where it operates. Nabors believes that the market for land drilling, workover and well-servicing contracts will continue to be competitive for the foreseeable future.

Our other operating segments represent a relatively smaller part of our business, and we have numerous competitors in each area. Our Canrig subsidiary is one of the four major manufacturers of top drives. Its largest competitors in that market are National Oilwell Varco, Tesco and MH Pyramid. Its largest competitors in the manufacture of rig instrumentation systems are Pason and National Oilwell Varco s Totco subsidiary. Mudlogging services are provided by a number of entities that serve the oil and gas industry on a regional basis. In the U.S. Lower 48 states, there are hundreds of rig transportation companies, and there are at least three or four that compete with Peak USA in each of its operating regions. In Alaska, Peak Oilfield Service principally competes with Alaska Petroleum Contractors for road, pad and pipeline maintenance, and is one of many drill site and road construction companies, the largest of which is VECO Corporation, and Alaska Interstate Construction principally competes with Wilder Construction Company and Pah River Construction for the construction of roads, bridges, dams, drill sites and other facility sites.

Our Business Strategy

Since 1987, with the installation of our current management team, Nabors has adhered to a consistent strategy aimed at positioning our Company to grow and prosper in good times and to mitigate adverse effects during periods of poor market conditions. We have maintained a financial posture that allows us to capitalize on market weakness and strength by adding to our business base, thereby enhancing our upside potential. The principal elements of our strategy have been to:

- Maintain flexibility to respond to changing conditions.
- Maintain a conservative and flexible balance sheet.
- Build cost effectively a base of premium assets.
- Build and maintain low operating costs through economies of scale.
- Develop and maintain long-term, mutually attractive relationships with key customers and vendors.
- Build a diverse business in long-term, sustainable and worthwhile geographic markets.

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Recognize and seize opportunities as they arise.

Continually improve safety, quality and efficiency.

Implement leading-edge technology where cost effective to do so.

Build shareholder value by an expansion of our oil and gas reserves and production.

Our business strategy is designed to allow us to grow and remain profitable in any market environment. The major developments in our business in the past three years illustrate our implementation of this strategy and its continuing success. Specifically during 2006, 2007 and the first half of 2008, we took advantage of the robust rig market in the United States and internationally to obtain a high volume of contracts for newly constructed rigs. A large proportion of these rigs are subject to long-term contracts with creditworthy customers with the most significant impact occurring in our International operations. This will not only expand our operations with the latest state-of-the-art rigs, which should better weather downturns in market activity, but eventually replace the oldest least capable rigs in our existing fleet. However, this positive trend slowed in the fourth quarter of 2008, due to the continued steady decline in natural gas and oil prices. As a result of lower commodity prices, many of our customers drilling programs have been reduced and the demand for additional rigs has been substantially reduced.

Acquisitions and Divestitures

We have grown from a land drilling business centered in the U.S. Lower 48 states, Canada and Alaska to an international business with operations on land and offshore in many of the major oil, gas and geothermal markets in the world. At the beginning of 1990, our fleet consisted of 44 actively marketed land drilling rigs in Canada, Alaska and in various international markets. Today, our worldwide fleet of actively marketed rigs consists of approximately 528 land drilling rigs, approximately 592 domestic and 171 international land workover and well-servicing rigs, 37 offshore platform rigs, 13 jack-up units, 3 barge rigs and a large component of trucks and fluid hauling vehicles. This growth was fueled in part by strategic acquisitions. Although Nabors continues to examine opportunities, there can be no assurance that attractive rigs or other acquisition opportunities will continue to be available, that the pricing will be economical or that we will be successful in making such acquisitions in the future.

On January 3, 2006, we completed an acquisition of 1183011 Alberta Ltd., a wholly owned subsidiary of Airborne Energy Solutions Ltd., through the purchase of all common shares outstanding for cash for a total purchase price of Cdn. $41.7 million (U.S. $35.8 million). In addition, we assumed debt, net of working capital, totaling approximately Cdn. $10.0 million (U.S. $8.6 million). Nabors Blue Sky Ltd. (formerly 1183011 Alberta Ltd.) owns 42 helicopters and fixed-wing aircraft and owns and operates a fleet of heliportable well-service equipment. The purchase price has been allocated based on final valuations of the fair value of assets acquired and liabilities assumed as of the acquisition date and resulted in goodwill of approximately U.S. $18.8 million. During the fourth quarter of 2008, the results of our year end impairment test of goodwill and intangible assets indicated a permanent impairment to goodwill and to an intangible asset of Nabors Blue Sky Ltd. As such, we recorded a non-cash impairment charge and writedown of intangible assets of $4.6 million and $4.6 million, respectively. See Note 2 Summary of Significant Accounting Policies in Part II, Item 8 Financial Statements and Supplementary Data.

On May 31, 2006, we completed an acquisition of Pragma Drilling Equipment Ltd. s business, which manufactures catwalks, iron roughnecks and other related oilfield equipment, through an asset purchase consisting primarily of intellectual property for a total purchase price of Cdn. $46.1 million (U.S. $41.5 million). The purchase price has been allocated based on final valuations of the fair market value of assets acquired and liabilities assumed as of the acquisition date and resulted in goodwill of approximately U.S. $10.5 million.

On August 8, 2007, we sold our Sea Mar business which had previously been included in Other Operating Segments. The assets included 20 offshore supply vessels and certain related assets, including a right under a vessel construction contract. The operating results of this business for all periods presented are accounted for as a discontinued operation in the accompanying audited consolidated statements of income.

From time to time, we may sell a subsidiary or group of assets outside of our core markets or business, if it is economically advantageous for us to do so.

Environmental Compliance

Nabors does not presently anticipate that compliance with currently applicable environmental regulations and controls will significantly change its competitive position, capital spending or earnings during 2009. Nabors believes it is in material compliance with applicable environmental rules and regulations, and the cost of such compliance is not material to the business or financial condition of Nabors. For a more detailed description of the environmental laws and regulations applicable to Nabors operations, see Part I, Item 1A. Risk Factors Changes to or noncompliance with governmental regulation or exposure to environmental liabilities could adversely affect Nabors results of operations.

ITEM 1A. RISK FACTORS

In addition to the other information set forth elsewhere in this Form 10-K, the following factors should be carefully considered when evaluating Nabors. The risks described below are not the only ones facing Nabors. Additional risks not presently known to us or that we currently deem immaterial may also impair our business operations.

Our business, financial condition or results of operations could be materially adversely affected by any of these risks.

Uncertain or negative global economic conditions could adversely affect our results of operations

During recent months, there has been substantial volatility and a decline in oil and natural gas prices due, at least in part, to the deteriorating global economic environment. In addition, there has been substantial uncertainty in the capital markets and access to financing is uncertain. These conditions could have an adverse effect on our industry and our business, including our future operating results and the ability to recover our assets, including goodwill, at their stated values. Many of our customers have curtailed their drilling programs, which, in many cases, has resulted in a decrease in demand for drilling rigs and a reduction in dayrates and utilization. Additionally, some customers have terminated drilling contracts prior to the expiration of their terms. A prolonged period of lower oil and natural gas prices could result in a continued decline in demand and/or dayrates. In addition, certain of our customers could experience an inability to pay suppliers, including our Company, in the event they are unable to access the capital markets to fund their business operations. Likewise, our suppliers may be unable to sustain their current level of operations, fulfill their commitments and/or fund future operations and obligations. Each of these could adversely affect our operations.

Fluctuations in oil and natural gas prices could adversely affect drilling activity and our revenues, cash flows and profitability

Our operations are materially dependent upon the level of activity in oil and gas exploration and production. Both short-term and long-term trends in oil and natural gas prices affect the level of such activity. Oil and natural gas prices and, therefore, the level of drilling, exploration and production activity can be volatile. Worldwide military, political and economic events, including initiatives by the Organization of Petroleum Exporting Countries, may affect both the demand for, and the supply of, oil and natural gas. Weather conditions, governmental regulation (both in the United States and elsewhere), levels of consumer demand, the availability of pipeline capacity, and other factors beyond our control may also affect the supply of and demand for oil and natural gas. The recent volatility and the effects of the recent significant decline in natural gas and oil prices is likely to continue in the near future, especially given the general contraction in the world s economy that began during 2008. We believe that any prolonged suppression of oil and natural gas prices would continue to depress the level of exploration and production activity. This would likely result in a corresponding decline in the demand for our services and could have an adverse effect on our revenues, cash flows and profitability. Lower oil and natural gas prices could also cause our customers to seek to terminate, renegotiate or fail to honor our drilling contracts; affect the fair market value of our rig fleet which in turn could trigger a write-down for accounting purposes; affect our ability to retain skilled rig personnel; and affect our ability to obtain access to capital to finance and grow our business. There can be no assurances as to the future level of demand for our services or future conditions in the oil and natural gas and oilfield services industries.

We operate in a highly competitive industry with excess drilling capacity, which may adversely affect our results of operations

The oilfield services industry in which we operate is very competitive. Contract drilling companies compete primarily on a regional basis, and competition may vary significantly from region to region at any particular time. Many drilling, workover and well-servicing rigs can be moved from one region to another in response to changes in levels of activity and market conditions, which may result in an oversupply of rigs in an area. In many markets in which we operate, the number of rigs available for use exceeds the demand for rigs, resulting in price competition. Most drilling and workover contracts are awarded on the basis of competitive bids, which also results in price competition. The land drilling market generally is more competitive than the offshore drilling market because there are larger numbers of rigs and competitors.

The nature of our operations presents inherent risks of loss that, if not insured or indemnified against, could adversely affect our results of operations

Our operations are subject to many hazards inherent in the drilling, workover and well-servicing industries, including blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment and damage or loss from inclement weather or natural disasters. Any of these hazards could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage and damage to the property of others. Our offshore operations are also subject to the hazards of marine operations including capsizing, grounding, collision, damage from hurricanes and heavy weather or sea conditions and unsound ocean bottom conditions. In addition, our international operations are subject to risks of war, civil disturbances or other political events. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our customers by contract for certain of these risks. To the extent that we are unable to transfer such risks to customers by contract or indemnification agreements, we seek protection through insurance. However, there is no assurance that such insurance or indemnification agreements will adequately protect us against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses. In addition, there can be no assurance that insurance will be available to cover any or all of these risks, or, even if available, that it will be adequate or that insurance premiums or other costs will not rise significantly in the future, so as to make such insurance prohibitive. It is possible that we will face continued upward pressure in our upcoming insurance renewals, our premiums and deductibles will be higher, and certain insurance coverage either will be unavailable or more expensive than it has been in the past. Moreover, our insurance coverage generally provides that we assume a portion of the risk in the form of a deductible. We may choose to increase the levels of deductibles (and thus assume a greater degree of risk) from time to time in order to minimize the overall cost to the Company.

Future price declines may result in a write-down of our asset carrying values

We follow the successful efforts method of accounting for our consolidated subsidiaries oil and gas activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Our provision for depletion is based on these capitalized costs and is determined on a property-by-property basis using the units-of-production method, with costs being amortized over proved developed reserves. Proved oil and gas properties are reviewed when circumstances suggest the need for such a review and, if required, the proved properties are written down to their estimated fair value. Unproved properties are reviewed periodically to determine if there has been impairment of the carrying value, with any such impairment charged to expense in that period. The estimated fair value of our proved reserves generally declines when there is a significant and sustained decline in oil and natural gas prices. Because of the low natural gas prices at December 31, 2008, we performed an impairment test on our oil and gas properties of our wholly owned Ramshorn business unit. As a result, we recorded a non-cash pre-tax impairment to our oil and gas properties which totaled $21.5 million. A sustained decrease in oil and natural gas prices could require a write-down of the value of our proved oil and gas properties if the estimated fair value of these properties falls below their net book value.

Our oil and gas joint ventures, which we account for under the equity method of accounting, utilize the full-cost method of accounting for costs related to oil and natural gas properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or market value of unproved properties. The full-cost ceiling is evaluated at the end of each quarter using then current prices for oil and natural gas, adjusted for the impact of derivatives accounted for as cash flow hedges. Our U.S., international and Canadian joint ventures have recorded non-cash pre-tax full cost ceiling test writedowns of which $228.3 million represents our proportionate share of the writedowns recorded during the three months ended December 31, 2008. Any sustained further decline in oil and natural gas prices, or other factors, without other mitigating circumstances, could cause other future write-downs of capitalized costs and non-cash asset impairments that could adversely affect our results of operations.

The profitability of our international operations could be adversely affected by war, civil disturbance, or political or economic turmoil, fluctuation in currency exchange rates and local import and export controls

We derive a significant portion of our business from international markets, including major operations in Canada, South America, Mexico, the Caribbean, the Middle East, the Far East, Russia and Africa. These operations are subject to various risks, including the risk of war, civil disturbances and governmental activities that may limit or disrupt markets, restrict the movement of funds or result in the deprivation of contract rights or the taking of property without fair compensation. In certain countries, our operations may be subject to the additional risk of fluctuating currency values and exchange controls. In the international markets in which we operate, we are subject to various laws and regulations that govern the operation and taxation of our business and the import and export of our equipment from country to country, the imposition, application and interpretation of which can prove to be uncertain.

Changes to or noncompliance with governmental regulation or exposure to environmental liabilities could adversely affect our results of operations

The drilling of oil and gas wells is subject to various federal, state, local and foreign laws, rules and regulations. Our cost of compliance with these laws, rules and regulations may be substantial. For example, federal law imposes a variety of regulations on responsible parties related to the prevention of oil spills and liability for damages from such spills. As an owner and operator of onshore and offshore rigs and transportation equipment, we may be deemed to be a responsible party under federal law. In addition,

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our well-servicing, workover and production services operations routinely involve the handling of significant amounts of waste materials, some of which are classified as hazardous substances. Our operations and facilities are subject to numerous state and federal environmental laws, rules and regulations, including, without limitation, laws concerning the containment and disposal of hazardous substances, oilfield waste and other waste materials, the use of underground storage tanks and the use of underground injection wells. We generally require customers to contractually assume responsibility for compliance with environmental regulations. However, we are not always successful in allocating to customers all of these risks nor is there any assurance that the customer will be financially able to bear those risks assumed.

We employ personnel responsible for monitoring environmental compliance and arranging for remedial actions that may be required from time to time and also use consultants to advise on and assist with our environmental compliance efforts. Liabilities are recorded when the need for environmental assessments and/or remedial efforts become known or probable and the cost can be reasonably estimated.

Laws protecting the environment generally have become more stringent than in the past and are expected to continue to become more so. Violation of environmental laws and regulations can lead to the imposition of administrative, civil or criminal penalties, remedial obligations, and in some cases injunctive relief. Such violations could also result in liabilities for personal injuries, property damage, and other costs and claims.

Under the Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or Superfund, and related state laws and regulations, liability can be imposed jointly on the entire group of responsible parties or separately on any one of the responsible parties, without regard to fault or the legality of the original conduct on certain classes of persons that contributed to the release of a hazardous substance into the environment. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

Changes in federal and state environmental regulations may also negatively impact oil and natural gas exploration and production companies, which in turn could have an adverse effect on us. For example, legislation has been proposed from time to time in Congress which would reclassify certain oil and natural gas production wastes as hazardous wastes, which would make the reclassified wastes subject to more stringent handling, disposal and clean-up requirements. Also, there are regulatory developments occurring in the domestic and international sectors in which we operate that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases that may be contributing to warming of the Earth s atmosphere, including the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol (an internationally applied protocol but one that the United States is not a participating member), the Regional Greenhouse Gas Initiative in the Northeastern United States, the Western Regional Climate Action Initiative in the Western United States, and the 2007 U.S. Supreme Court decision in *Massachusetts, et al. v. EPA* that greenhouse gases are an air pollutant under the federal Clean Air Act and thus subject to future regulation. The enactment of such hazardous waste legislation or future or more stringent regulation of greenhouse gases could dramatically increase operating costs for oil and natural gas companies and could reduce the market for our services by making many wells and/or oilfields uneconomical to operate.

The Oil Pollution Act of 1990, as amended, contains provisions specifying responsibility for removal costs and damages resulting from discharges of oil into navigable waters or onto the adjoining shorelines. In addition, the Outer Continental Shelf Lands Act provides the federal government with broad discretion in regulating the leasing of offshore oil and gas production sites.

As a holding company, we depend on our subsidiaries to meet our financial obligations

We are a holding company with no significant assets other than the stock of our subsidiaries. In order to meet our financial needs, we rely exclusively on repayments of interest and principal on intercompany loans made by us to our operating subsidiaries and income from dividends and other cash flow from such subsidiaries. There can be no assurance that our operating subsidiaries will generate sufficient net income to pay upstream dividends or cash flow to make payments of interest and principal to us in respect of their intercompany loans. In addition, from time to time, our operating subsidiaries may enter into financing arrangements which may contractually restrict or prohibit such upstream payments to us. There may also be adverse tax consequences associated with making dividend payments upstream.

We do not currently intend to pay dividends

We have not paid any cash dividends on our common shares since 1982. Nabors does not currently intend to pay any cash dividends on its common shares. However, we can give no assurance that we will not reevaluate our position on dividends in the future.

Because our option, warrant and convertible securities holders have a considerable number of common shares available for issuance and resale, significant issuances or resales in the future may adversely affect the market price of our common shares

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As of February 23, 2009, we had 800,000,000 authorized common shares, of which 282,930,433 shares were outstanding. In addition, 42,276,821 common shares were reserved for issuance pursuant to option and employee benefit plans, and 78,013,925 shares were reserved for issuance upon conversion or repurchase of outstanding senior exchangeable notes. In addition, up to 104,520 of our common shares could be issuable on exchange of the shares of Nabors Exchangeco (Canada) Inc. We also plan to file a shelf registration statement to replace our shelf registration which expired in December 2008. The new shelf registration statement will automatically become effective on filing with the SEC and will permit us to sell various types of securities from time to time. The sale, or availability for sale, of substantial amounts of our common shares in the public market, whether directly by us or resulting from the exercise of warrants or options (and, where applicable, sales pursuant to Rule 144 of the Securities Act) or the conversion into common shares, or repurchase of debentures and notes using common shares, would be dilutive to existing security holders, could adversely affect the prevailing market price of our common shares and could impair our ability to raise additional capital through the sale of equity securities.

Provisions of our organizational documents and executive contracts may deter a change of control transaction and decrease the likelihood of a shareholder receiving a change of control premium

Our Board of Directors is divided into three classes, with each class serving a staggered three-year term. In addition, our Board of Directors has the authority to issue a significant amount of common shares and up to 25,000,000 preferred shares and to determine the price, rights (including voting rights), conversion ratios, preferences and privileges of the preferred shares, in each case without further vote or action by the holders of the common shares. Although we have no present plans to issue preferred shares, the classified Board and our Board s ability to issue additional preferred shares may discourage, delay or prevent changes in control of Nabors that are not supported by our Board, thereby possibly preventing certain of our shareholders from realizing a possible premium on their shares. In addition, the requirement in the indenture for our $2.75 billion senior exchangeable notes due 2011 to pay a make-whole premium in the form of an increase in the exchange rate in certain circumstances could have the effect of making a change in control of Nabors more expensive.

The Company has existing employment contracts with Nabors Chairman and Chief Executive Officer, Eugene M. Isenberg, and its Deputy Chairman, President and Chief Operating Officer, Anthony G. Petrello. These employment contracts have Change of Control provisions that could result in significant cash payments to Messrs. Isenberg and Petrello.

We have a substantial amount of debt outstanding

As of December 31, 2008, we have long-term debt of approximately $4.1 billion, including current maturities of $225.0 million, and cash and cash equivalents and investments of $826.1 million, including $240.0 million of long-term investments and other receivables. Long-term investments and other receivables include $224.2 million in oil and gas financing receivables. If our $2.75 billion 0.94% senior exchangeable notes are exchanged, the required cash payment could have a significant impact on our level of cash and cash equivalents and investments available to meet our other cash obligations. We have a gross funded debt to capital ratio of 0.44:1 and a net funded debt to capital ratio of 0.39:1. The gross funded debt to capital ratio is calculated by dividing funded debt by funded debt plus deferred tax liabilities net of deferred tax assets plus capital. Funded debt is defined as the sum of (1) short-term borrowings, (2) current portion of long-term debt and (3) long-term debt. Capital is defined as shareholders equity. The net funded debt to capital ratio is calculated by dividing net funded debt by net funded debt plus deferred tax liabilities net of deferred tax assets 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 reduced by the sum of cash and cash equivalents and short-term and long-term investments. Capital is defined as shareholders equity. Both of these ratios are methods for calculating the amount of leverage a company has in relation to its capital.

During January and through February 23, 2009, we purchased $427.7 million par value of our $2.75 billion 0.94% senior exchangeable notes due 2011 in the open market for cash totaling $370.6 million, leaving $2.22 billion par value outstanding.

On January 12, 2009, Nabors Industries, Inc., our wholly owned subsidiary, (Nabors Delaware) issued $1.125 billion aggregate principal amount of 9.25% senior notes due 2019 that are fully and unconditionally guaranteed by Nabors Industries Ltd. See Note 22 Subsequent Event in Part II, Item 8. Financial Statements and

Supplementary Data.

In January and through February 23, 2009 we repurchased $56.6 million par value of our $225 million principal amount of 4.875% senior notes due August 2009 in the open market for cash totaling $56.8 million.

Our access to borrowing capacity could be affected by the recent instability in the global financial markets

Our ability to access capital markets or to otherwise obtain sufficient financing is enhanced by our senior unsecured debt ratings as provided by Dominion Bond Rating Service (DBRS), Fitch Ratings, Moody s Investor Service and Standard & Poor s, which are currently BBB+, BBB+, Baa1 and BBB+ (Negative Watch) , respectivel and our historical ability to access those markets as

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needed. However, recent instability in the global financial markets has resulted in a significant reduction in the availability of funds from capital markets and other credit markets and as a result our ability to access these markets at this time may be significantly reduced. In addition, Standard & Poor s recently affirmed its BBB+ credit rating on Nabors, but revised its outlook to negative from stable due primarily to worsening industry conditions. A credit downgrade by Standard & Poor s may impact our future ability to access credit markets.

Our ability to perform under new contracts and to grow our business as forecasted depends to a substantial degree on timely delivery of rigs and equipment from our suppliers

The operating revenues and net income for our Contract Drilling subsidiaries depend to a substantial degree on the timely delivery of rigs and equipment from our suppliers as part of our recently expanded capital programs. We can give no assurances that our suppliers will meet expected delivery schedules for delivery of these new rigs and equipment or that the new rigs and equipment will be free from defects. Delays in the delivery of new rigs and equipment and delays incurred in correcting any defects in such rigs and equipment could cause us to fail to meet our operating forecasts and could subject us to late delivery penalties under contracts with our customers.

We may have additional tax liabilities

We are subject to income taxes in the United States and numerous foreign jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. In the ordinary course of our business, there are many transactions and calculations where the ultimate tax determination is uncertain. We are regularly under audit by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than that which is reflected in income tax provisions and accruals. Based on the results of an audit or litigation, a material effect on our financial position, income tax provision, net income, or cash flows in the period or periods for which that determination is made could result.

It is possible that future changes to tax laws (including tax treaties) could have an impact on our ability to realize the tax savings recorded to date as well as future tax savings, resulting from our 2002 corporate reorganization.

On September 14, 2006, Nabors Drilling International Limited, one of our wholly owned Bermuda subsidiaries (NDIL), received a Notice of Assessment (the Notice) from the Mexican Servicio de Administracion Tributaria (the SAT) in connection with the audit of NDIL s Mexican branch for tax year 2003. The Notice proposes to deny depreciation expense deductions relating to drilling rigs operating in Mexico in 2003. The notice also proposes to deny a deduction for payments made to an affiliated company for the procurement of labor services in Mexico. The amount assessed by the SAT was approximately $19.8 million (including interest and penalties). Nabors and its tax advisors previously concluded that the deduction of said amounts was appropriate and more recently that the position of the SAT lacks merit. NDIL s Mexican branch took similar deductions for depreciation and labor expenses in 2004, 2005, 2006, 2007 and 2008. It is likely that the SAT will propose the disallowance of these deductions upon audit of NDIL s Mexican branch s 2004, 2005, 2006, 2007 and 2008 tax years.

Proposed tax legislation could mitigate or eliminate the benefits of our 2002 reorganization as a Bermuda company

Various bills have been introduced in Congress which could reduce or eliminate the tax benefits associated with our reorganization as a Bermuda company. Legislation enacted by Congress in 2004 provides that a corporation that reorganized in a foreign jurisdiction on or after March 4, 2003 shall be treated as a domestic corporation for United States federal income tax purposes. Nabors reorganization was completed June 24, 2002. There have been and we expect that there may continue to be legislation proposed by Congress from time to time applicable to certain companies that completed such reorganizations on or after March 20, 2002 which, if enacted, could limit or eliminate the tax benefits associated with our reorganization.

Because we cannot predict whether legislation will ultimately be adopted, no assurance can be given that the tax benefits associated with our reorganization will ultimately accrue to the benefit of the Company and its shareholders. It is possible that future changes to the tax laws (including tax treaties) could have an impact on our ability to realize the tax savings recorded to date as well as future tax savings resulting from our reorganization.

Legal proceedings could affect our financial condition and results of operations

We are from time to time subject to legal proceedings or governmental investigations which include employment, tort, intellectual property and other claims, and purported class action and shareholder derivative actions. We also are subject to complaints or allegations from former, current or prospective employees from time to time, alleging violations of employment-related laws. Lawsuits or claims could result in decisions against us which could have an adverse effect on our financial condition or results of operations.

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Our financial results could be affected by changes in the value of our investment portfolio

We invest our excess cash in a variety of investment vehicles, many of which are subject to market fluctuations resulting from a variety of economic factors or factors associated with a particular investment, including without limitation, overall declines in the equity markets, currency and interest rate fluctuations, volatility in the credit markets, exposures related to concentrations of investments in a particular fund or investment, exposures related to hedges of financial positions, and the performance of particular fund or investment managers. As a result, events or developments which negatively affect the value of our investments could have an adverse effect on our results of operations.

The loss of key executives could reduce our competitiveness and prospects for future success

The successful execution of our strategies central to our future success will depend, in part, on a few of our key executive officers. We have entered into employment agreements with our Chairman and Chief Executive Officer, Mr. Eugene M. Isenberg and our Deputy Chairman, President and Chief Operating Officer, Mr. Anthony G. Petrello, to secure their employment through September 30, 2010. We do not carry key man insurance. The loss of Mr. Isenberg or Mr. Petrello could have an adverse effect on our financial condition or results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Many of the international drilling rigs and certain of the Alaska rigs in our fleet are supported by mobile camps which house the drilling crews and a significant inventory of spare parts and supplies. In addition, we own various trucks, forklifts, cranes, earth moving and other construction and transportation equipment and own various helicopters, fixed-wing aircraft and heliportable well-service equipment, which are used to support drilling and logistics operations.

Nabors and its subsidiaries own or lease executive and administrative office space in Hamilton, Bermuda (principal executive office); Houston, Texas; Anchorage, Alaska; New Iberia and Youngsville, Louisiana; Bakersfield, California; Alice, Bridgeport, Corpus Christi, Kilgore, Longview, Magnolia, Midland and Odessa, Texas; Casper, Wyoming; Alberta, Canada; Oklahoma City and Pocola, Oklahoma; Billings, Montana; Williston, North Dakota; Fort Lupton and Fruita, Colorado; Dubai, U.A.E.; Dhahran, Saudi Arabia; Hassi-Messaoud, Algeria; Almaty, Kazakhstan; Ahmadi, Kuwait; Kuala Lumpur, Malaysia; Pointe Noire, Congo; Moscow, Russia; and Ploeisti, Romania. We also own or lease a number of facilities and storage yards used in support of operations in each of our geographic markets.

Nabors and its subsidiaries own certain mineral interests in connection with their investing and operating activities. Nabors does not consider these properties to be material to its overall operations.

Additional information about our properties can be found in Notes 2 and 7 (each, under the caption Property, Plant and Equipment) and 15 (under the caption Operating Leases) in Part II, Item 8. Financial Statements and Supplementary Data. The revenues and property, plant and equipment by geographic area for the fiscal years ended December 31, 2006, 2007 and 2008, can be found in Note 20 in Part II, Item 8. Financial Statements and Supplementary Data. A description of our rig fleet is included under the caption Introduction in Part I, Item 1. Business.

Nabors management believes that our existing equipment and facilities and our planned expansion of our equipment and facilities through our capital expenditure programs currently in process are adequate to support our current level of operations as well as an expansion of drilling operations in those geographical areas where we may expand.

ITEM 3. LEGAL PROCEEDINGS

Nabors and its subsidiaries are defendants or otherwise involved in a number of lawsuits in the ordinary course of business. We estimate the range of our liability related to pending litigation when we believe the amount and range of loss can be estimated. We record our best estimate of a loss when the loss is considered probable. When a liability is probable and there is a range of estimated loss with no best estimate in the range, we record the minimum estimated liability related to the lawsuits or claims. As additional information becomes available, we assess the potential liability related to our pending litigation and claims and revise our estimates. Due to uncertainties related to the resolution of lawsuits and claims, the ultimate outcome may differ from our estimates. In the opinion of management and based on liability accruals provided, our ultimate exposure with respect to these pending lawsuits and

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claims is not expected to have a material adverse effect on our consolidated financial position or cash flows, although they could have a material adverse effect on our results of operations for a particular reporting period.

On July 5, 2007, we received an inquiry from the U.S. Department of Justice relating to its investigation of one of our vendors and compliance with the Foreign Corrupt Practices Act. The inquiry relates to transactions with and involving Panalpina, a vendor which provides freight forwarding and customs clearance services to certain of our affiliates. To date, the inquiry has focused on transactions in Kazakhstan, Saudi Arabia, Algeria and Nigeria. The Audit Committee of our Board of Directors has engaged outside counsel to review certain transactions with this vendor, and their review is ongoing. The Audit Committee of our Board of Directors has received periodic updates at its regularly scheduled meetings and the Chairman of the Audit Committee has received updates between meetings as circumstances warrant. The investigation includes a review of certain amounts paid to and by Panalpina in connection with the obtaining of permits for the temporary importation of equipment and clearance of goods and materials through customs. Both the SEC and the U.S. Department of Justice have been advised of the Company s investigation. The ultimate outcome of this review or the effect of implementing any further measures which may be necessary to ensure full compliance with the applicable laws cannot be determined at this time.

A court in Algeria has entered a judgment against the Company related to certain alleged customs infractions. The Company believes it did not receive proper notice of the judicial proceedings against it, and that the amount of the judgment is excessive. We intend to assert the lack of legally required notice as a basis for challenging the judgment on appeal. Based upon our understanding of applicable law and precedent, we believe that this challenge will be successful. We do not believe that a loss is probable and have not accrued any amounts related to this matter. However, the ultimate resolution of this matter, and the timing of such resolution, is uncertain. If the Company is ultimately required to pay a fine or judgment related to this matter, the amount of the loss could range from approximately $140,000 to $20 million.

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

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED SHAREHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

STOCK PERFORMANCE GRAPH

The following graph illustrates comparisons of five-year cumulative total returns among Nabors, the S&P 500 Index and the Dow Jones Oil Equipment and Services Index. Total return assumes $100 invested on December 31, 2003 in shares of Nabors, the S&P 500 Index, and the Dow Jones Oil Equipment and Services Index. It also assumes reinvestment of dividends and is calculated at the end of each calendar year, December 31, 2004 to December 31, 2008.

	2004	2005	2006	2007	2008
Nabors Industries Ltd.	124	183	144	132	**58**
S&P 500 Index	111	116	135	142	**90**
Dow Jones Oil Equipment and Services Index	135	205	233	338	**138**

I. Market and Share Prices

Our common shares are traded on the New York Stock Exchange under the symbol NBR . At February 23, 2009, there were approximately 1,575 shareholders of record. We have not paid any cash dividends on our common shares since 1982. Nabors does not currently intend to pay any cash dividends on its common shares. However, we can give no assurance that we will not reevaluate our position on dividends in the future.

On December 13, 2005, our Board of Directors approved a two-for-one stock split of our common shares to be effectuated in the form of a stock dividend. The stock dividend was distributed on April 17, 2006 to shareholders of record on March 31, 2006. For all balance sheets presented, capital in excess of par value was reduced by $.2 million and common shares were increased by $.2 million.

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The following table sets forth the reported high and low sales prices of our common shares as reported on the New York Stock Exchange for the periods indicated.

	Share Price	
Calendar Year	**High**	**Low**
2007 First quarter	32.74	27.53
Second quarter	36.42	29.59
Third quarter	34.10	27.05
Fourth quarter	31.23	26.00
2008 First quarter	34.14	23.61
Second quarter	50.58	33.06
Third quarter	50.35	22.50
Fourth quarter	24.88	9.72

The following table provides information relating to Nabors repurchase of common shares during the three months ended December 31, 2008:

Period (In thousands, except per share amounts)	**Total Number of Shares Purchased**	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Program**	**Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program** (1)
October 1 October 31, 2008	46 (2)	$22.59		$ 35,458
November 1 November 30, 2008	1 (2)	$22.59		$ 35,458
December 1 December 31, 2008	953 (2)	$22.59		$ 35,458

(1) In July 2006 our Board of Directors authorized a share repurchase program under which we may repurchase up to $500 million of our common shares in the open market or in privately negotiated transactions. This program supersedes and

cancels our previous share repurchase program. Through December 31, 2008, $464.5 million of our common shares have been repurchased under this program. As of December 31, 2008, we had the capacity to repurchase up to an additional $35.5 million of our common shares under the July 2006 share repurchase program.

(2) In September 2008 we entered into a three-month written put option for 1 million of our common shares with a strike price of $25 per common share. We settled this contract during the fourth quarter of 2008 and paid cash of $22.6 million, net of the premium received on this contract.

See Part III, Item 12. for a description of securities authorized for issuance under equity compensation plans.

II. Dividend Policy

See Part I, Item 1A. Risk Factors We do not currently intend to pay dividends.

III. Shareholder Matters

Bermuda has exchange controls which apply to residents in respect to the Bermudian dollar. As an exempt company, Nabors is considered to be nonresident for such controls; consequently, there are no Bermuda governmental restrictions on the Company s ability to make transfers and carry out transactions in all other currencies, including currency of the United States.

There is no reciprocal tax treaty between Bermuda and the United States regarding withholding taxes. Under existing Bermuda law there is no Bermuda income or withholding tax on dividends paid by Nabors to its shareholders. Furthermore, no Bermuda tax is levied on the sale or transfer (including by gift and/or on the death of the shareholder) of Nabors common shares (other than by shareholders resident in Bermuda).

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ITEM 6. SELECTED FINANCIAL DATA

Operating Data (1)(2) **(In thousands, except per share amounts and ratio data)**	**Year Ended December 31,** **2008**	**2007**	**2006**	**2005**	**2004**
Revenues and other income:					
Operating revenues	$ 5,511,896	$ 4,938,848	$ 4,707,289	$ 3,394,472	$ 2,351,571
Earnings (losses) from unconsolidated affiliates	(229,834)	17,724	20,545	5,671	4,057
Investment income (loss)	21,726	(15,891)	102,007	85,428	50,044
Total revenues and other income	5,303,788	4,940,681	4,829,841	3,485,571	2,405,672
Costs and other deductions:					
Direct costs	3,110,316	2,764,559	2,511,392	1,958,538	1,542,364
General and administrative expenses	479,984	436,282	416,610	247,129	192,692
Depreciation and amortization	611,066	467,730	364,653	285,054	248,057
Depletion	46,979	72,182	38,580	46,894	45,460
Interest expense	91,620	53,702	46,586	44,849	48,507
Losses (gains) on sales, retirements and impairments of long-lived assets and other expense (income), net	7,613	10,895	24,118	45,952	(5,036)
Goodwill and intangible asset impairment	154,586				
Total costs and other deductions	4,502,164	3,805,350	3,401,939	2,628,416	2,072,044
Income from continuing operations before income taxes	801,624	1,135,331	1,427,902	857,155	333,628
Income tax expense	250,451	239,664	434,893	219,000	32,660
Income from continuing operations, net of tax	551,173	895,667	993,009	638,155	300,968
Income from discontinued operations, net of tax		35,024	27,727	10,540	1,489
Net income	$ 551,173	$ 930,691	$ 1,020,736	$ 648,695	$ 302,457
Earnings per share:					
Basic from continuing operations	$ 1.98	$ 3.21	$ 3.42	$ 2.05	$ 1.01
Basic from discontinued operations		.13	.10	.03	.01
Total Basic	$ 1.98	$ 3.34	$ 3.52	$ 2.08	$ 1.02
Diluted from continuing operations	$ 1.93	$ 3.13	$ 3.31	$ 1.97	$ .96
Diluted from discontinued operations		.12	.09	.03	
Total Diluted	$ 1.93	$ 3.25	$ 3.40	$ 2.00	$ .96
Weighted-average number of common shares outstanding:					
Basic	278,166	279,026	290,241	312,134	297,872
Diluted	285,285	286,606	299,827	324,378	328,060
Capital expenditures and acquisitions of businesses (3)	$ 1,561,423	$ 1,921,221	$ 1,997,971	$ 1,003,269	$ 544,429

Interest coverage ratio (4)	20.9:1	32.5:1	38.1:1	25.6:1	12.9:1

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Balance Sheet Data (2) (In thousands, except ratio data)	As of December 31, 2008	2007	2006	2005	2004
Cash, cash equivalents, short-term and long-term investments and other receivables (5)	$ 826,063	$ 1,179,639	$1,653,285	$1,646,327	$1,411,047
Working capital	1,037,734	710,980	1,650,496	1,264,852	821,120
Property, plant and equipment, net	7,282,042	6,632,612	5,410,101	3,886,924	3,275,495
Total assets	10,467,982	10,103,382	9,142,303	7,230,407	5,862,609
Long-term debt	3,887,711	3,306,433	4,004,074	1,251,751	1,201,686
Shareholders equity	$ 4,692,119	$ 4,514,121	$3,536,653	$3,758,140	$2,929,393
Funded debt to capital ratio:					
Gross (6)	0.44:1	0.44:1	0.50:1	0.32:1	0.38:1
Net (7)	0.39:1	0.36:1	0.37:1	0.08:1	0.15:1

(1) All periods present the Sea Mar business as a discontinued operation.

(2) Our acquisitions results of operations and financial position have been included beginning on the respective dates of acquisition and include Pragma Drilling Equipment Ltd. assets (May 2006), 1183011 Alberta Ltd. (January 2006), Sunset Well Service, Inc. (August 2005), Alexander Drilling, Inc. assets (June 2005), Phillips Trucking, Inc. assets (June 2005), and

Rocky Mountain Oil Tools, Inc. assets (March 2005).

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

(4) The interest coverage ratio from continuing operations is computed by calculating the sum of income from continuing operations before income taxes, interest expense, depreciation and amortization, depletion expense, goodwill and intangible asset impairments and our proportionate share of non-cash pre-tax full cost ceiling writedowns from our oil and gas joint ventures less investment income (loss) and then dividing by

interest expense. This ratio is a method for calculating the amount of operating cash flows available to cover interest expense. The interest coverage ratio from continuing operations is not a measure of operating performance or liquidity defined by accounting principles generally accepted in the United States of America (GAAP) and may not be comparable to similarly titled measures presented by other companies.

(5) The December 31, 2008 and 2007 amounts include \$1.9 million and \$53.1 million, respectively, in cash proceeds receivable from brokers from the sale of certain long-term investments that are included in other current assets and \$224.2 million and \$123.3 million,

respectively, in oil and gas financing receivables that are included in long-term investments and other receivables.

(6) The gross funded debt to capital ratio is calculated by dividing funded debt by funded debt plus deferred tax liabilities, net of deferred tax assets plus capital. Funded debt is defined as the sum of (1) short-term borrowings, (2) current portion of long-term debt and (3) long-term debt. Capital is defined as shareholders equity. The gross funded debt to capital ratio is not a measure of operating performance or liquidity defined by GAAP and may not be comparable to similarly titled measures presented by other companies.

(7) The net funded debt to capital ratio is calculated by dividing net funded debt by net funded debt plus deferred tax liabilities, net of deferred tax assets 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 reduced by the sum of cash and cash equivalents and short-term and long-term investments and other receivables. Capital is defined as shareholders equity. The net funded debt to capital ratio is not a measure of operating performance or liquidity defined by GAAP and may not be comparable to similarly titled measures presented by other companies.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management Overview

The following Management s Discussion and Analysis of Financial Condition and Results of Operations is intended to help the reader understand the results of our operations and our financial condition. This information is provided as a supplement to, and should be read in conjunction with, our consolidated financial statements and the accompanying notes to our consolidated financial statements.

Nabors is the largest land drilling contractor in the world. We conduct oil, gas and geothermal land drilling operations in the U.S. Lower 48 states, Alaska, Canada, South America, Mexico, the Caribbean, the Middle East, the Far East, Russia and Africa. Nabors also is one of the largest land well-servicing and workover contractors in the United States and Canada and is a leading provider of offshore platform workover and drilling rigs in the United States and multiple international markets. To further supplement and complement our primary business, we offer a wide range of ancillary well-site services, including engineering, transportation, construction, maintenance, well logging, directional drilling, rig instrumentation, data collection and other support services, in selected domestic and international markets. We offer logistics services for onshore drilling in Canada using helicopter and fixed-winged aircraft. We manufacture and lease or sell top drives for a broad range of drilling applications, directional drilling systems, rig instrumentation and data collection equipment, pipeline handling equipment and rig reporting software. We also invest in oil and gas exploration, development and production activities worldwide.

The majority of our business is conducted through our various Contract Drilling operating segments, which include our drilling, workover and well-servicing operations, on land and offshore. Our oil and gas exploration, development and production operations are included in a category labeled Oil and Gas for segment reporting purposes. Our operating segments engaged in drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction and logistics operations are aggregated in a category labeled Other Operating Segments for segment reporting purposes.

Our 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 magnitude of customer spending on new and existing wells is the primary driver of our business. The primary determinate of customer spending is the degree of their cash flow and earnings which are largely determined by natural gas prices in our U.S. Lower 48 Land Drilling and Canadian Drilling operations, while oil prices are the primary determinate in our Alaskan, International, U.S. Offshore (Gulf of Mexico), Canadian Well-servicing and U.S. Land Well-servicing operations. The following table sets forth natural gas and oil price data per Bloomberg for the last three years:

	Year Ended December 31,			Increase / (Decrease)			
	2008	2007	2006	2008 to 2007		2007 to 2006	
Commodity prices:							
Average Henry Hub natural gas spot price ($/million cubic feet (mcf))	$ 8.89	$ 6.97	$ 6.73	$ 1.92	28%	$0.24	4%
Average West Texas intermediate crude oil spot price ($/barrel)	$99.92	$72.23	$66.09	$27.69	38%	$6.14	9%

Beginning in the second half of 2008, there has been a significant decrease in natural gas and oil prices. Natural gas prices, which averaged $10.03 per mcf during the first half of 2008, declined significantly, averaging only $7.74 per mcf during the second half of 2008 and $5.84 per mcf during December 2008. The decline has continued as natural gas prices have averaged $4.96 per mcf during the period January 1, 2009 through February 23, 2009.

Oil prices also declined in the second half of 2008 with average prices of $111.14 per barrel during the first half of 2008, decreasing to average prices of $88.88 per barrel during the second half of 2008 and $41.44 per barrel during December 2008. Oil prices remain depressed and have averaged $40.22 per barrel during the period January 1, 2009 through February 23, 2009.

This significant decline in commodity prices has, at least in part, been driven by the significant deterioration of the global economic environment including the extreme volatility in the capital and credit markets. All of these factors are having an adverse effect on our customers spending plans for exploration, production and development activities which has had a significant negative impact on our operations beginning in December 2008.

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Operating revenues and Earnings from unconsolidated affiliates for the year ended December 31, 2008 totaled $5.3 billion, representing an increase of $325.5 million, or 7% as compared to the year ended December 31, 2007. Adjusted income derived from operating activities and net income for the year ended December 31, 2008 totaled $1.0 billion and $551.2 million ($1.93 per diluted share), respectively, representing decreases of 15% and 41%, respectively, compared to the year ended December 31, 2007. Operating revenues and Earnings from unconsolidated affiliates for the year ended December 31, 2007 totaled $5.0 billion, representing an increase of $228.7 million, or 5% as compared to the year ended December 31, 2006. Adjusted income derived from operating activities and net income for the year ended December 31, 2007 totaled $1.2 billion and $930.7 million ($3.25 per diluted share), respectively, representing decreases of 13% and 9%, respectively, compared to the year ended December 31, 2006.

Our operating results were negatively impacted as a result of non-cash, pre-tax charges arising from oil and gas full cost ceiling test writedowns and goodwill and intangible asset impairments. Our Earnings (losses) from Unconsolidated Affiliates line in our income statement includes $228.3 million, representing our proportionate share of non-cash pre-tax full cost ceiling test writedowns from our U.S., international and Canadian joint ventures during the three months ended December 31, 2008. Additionally, we recorded non-cash pre-tax impairment charges of $21.5 million related to our wholly owned Ramshorn business unit under application of the successful efforts method of accounting related to oil and gas properties during the three months ended December 31, 2008. Charges from our U.S., international and Canadian joint ventures and our wholly owned Ramshorn business unit are included in our Oil and Gas operating segment results. Our Canada Well-servicing and Drilling operating segment and Nabors Blue Sky Ltd., one of our Canadian subsidiaries reported in our Other Operating Segments include $145.4 million and $4.6 million non-cash pre-tax goodwill and intangible asset impairment charges to reduce the carrying value of these assets to their estimated fair value due to the duration of the economic downturn in Canada and the lack of certainty regarding eventual recovery. Excluding these charges, our operating results were slightly higher primarily due to our U.S. Lower 48 Land Drilling, International Drilling and Other Operating segments resulting from higher average dayrates and activity levels resulting from sustained higher natural gas and oil prices throughout 2007 and the majority of 2008, partially offset by increased operating costs and higher depreciation expense due to our capital expenditures.

The decrease in our adjusted income derived from operating activities from 2006 to 2007 related primarily to our U.S. Lower 48 Land Drilling, Canada Drilling and Well-servicing, and our U.S. Well-servicing operations, where activity levels decreased despite slightly higher natural gas prices and higher oil prices. Operating results were further negatively impacted by higher levels of depreciation expense due to our capital expenditures. Partially offsetting the decreases in our adjusted income derived from operating activities were the increases in operating results from our International operations and to a lesser extent by our Alaska operations, driven by high oil prices. In addition, our net income and earnings per share for 2007 has decreased compared to 2006 as a result of investment net losses during 2007 only partially offset by a lower effective tax rate and a lower number of average shares outstanding.

Our operating results for 2009 are expected to decrease from levels realized during 2008 given our current expectation of the continuation of lower commodity prices during 2009 and the related impact on drilling and well-servicing activity and dayrates. The decrease in drilling activity and dayrates is expected to have a significant impact on our U.S. Lower 48 Land Drilling and our U.S. Land Well-servicing operations. In our U.S. Lower 48 Land Drilling operations, our rig count has decreased from its peak during October 2008 of 273 rigs to 162 rigs currently operating as of February 23, 2009. Our Well-servicing activity is down approximately 45% from its October 2008 peak of 105,872 hours when compared to estimated rig hours for February 2009. We expect our International operations to increase during 2009 resulting from the deployment of additional rigs under long-term contracts and the renewal of existing contracts at higher dayrates.

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

(In thousands, except percentages and rig activity)	**Year Ended December 31, 2008**	**2007**	**2006**	**Increase/(Decrease) 2008 to 2007**	**2007 to 2006**
Reportable segments:					
Operating revenues and Earnings (losses) from unconsolidated					

affiliates from continuing operations: (1)							
Contract Drilling: (2)							
U.S. Lower 48 Land Drilling	$ 1,878,441	$ 1,710,990	$ 1,890,302	$ 167,451	10%	$ (179,312)	(9%)
U.S. Land Well-servicing	758,510	715,414	704,189	43,096	6%	11,225	2%
U.S. Offshore	252,529	212,160	221,676	40,369	19%	(9,516)	(4%)
Alaska	184,243	152,490	110,718	31,753	21%	41,772	38%
Canada	502,695	545,035	686,889	(42,340)	(8%)	(141,854)	(21%)

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(In thousands, except percentages and rig activity)	Year Ended December 31, 2008	2007	2006	Increase/(Decrease) 2008 to 2007		2007 to 2006	
International	1,372,168	1,094,802	746,460	277,366	25%	348,342	47%
Subtotal Contract Drilling (3)	4,948,586	4,430,891	4,360,234	517,695	12%	70,657	2%
Oil and Gas (4) (5)	(151,465)	152,320	59,431	(303,785)	(199%)	92,889	156%
Other Operating Segments (6) (7)	683,186	588,483	505,286	94,703	16%	83,197	16%
Other reconciling items (8)	(198,245)	(215,122)	(197,117)	16,877	8%	(18,005)	(9%)
Total	$ 5,282,062	$ 4,956,572	$ 4,727,834	$ 325,490	7%	$ 228,738	5%
Adjusted income (loss) derived from operating activities from continuing operations: (1)(9)							
Contract Drilling:							
U.S. Lower 48 Land Drilling	$ 628,579	$ 596,302	$ 821,821	$ 32,277	5%	$ (225,519)	(27%)
U.S. Land Well-servicing	148,626	156,243	199,944	(7,617)	(5%)	(43,701)	(22%)
U.S. Offshore	59,179	51,508	65,328	7,671	15%	(13,820)	(21%)
Alaska	52,603	37,394	17,542	15,209	41%	19,852	113%
Canada	61,040	87,046	185,117	(26,006)	(30%)	(98,071)	(53%)
International	407,675	332,283	208,705	75,392	23%	123,578	59%
Subtotal Contract Drilling(3)	1,357,702	1,260,776	1,498,457	96,926	8%	(237,681)	(16%)
Oil and Gas(4)(5)	(228,027)	56,133	4,065	(284,160)	(506%)	52,068	n/m(6)
Other Operating Segments (7)(8)	68,572	35,273	30,028	33,299	94%	5,245	17%
Other reconciling items (11)	(164,530)	(136,363)	(135,951)	(28,167)	(21%)	(412)	0%
Total	1,033,717	1,215,819	1,396,599	(182,102)	(15%)	(180,780)	(13%)
Interest expense	(91,620)	(53,702)	(46,586)	(37,918)	(71%)	(7,116)	(15%)
Investment (loss) income	21,726	(15,891)	102,007	37,617	237%	(117,898)	(116%)
(Losses) gains on sales, retirements and impairments of long-lived assets and other income (expense), net	(7,613)	(10,895)	(24,118)	3,282	30%	13,223	55%
Goodwill and intangible asset impairment (12)	(154,586)			(154,586)	(100%)		
Income from continuing operations before income taxes	$ 801,624	$ 1,135,331	$ 1,427,902	$ (333,707)	(29%)	$ (292,571)	(20%)
Rig activity:							
Rig years: (13)							
U.S. Lower 48 Land Drilling	247.9	229.4	255.5	18.5	8%	(26.1)	(10%)
U.S. Offshore	17.6	15.8	16.4	1.8	11%	(0.6)	(4%)
Alaska	10.9	8.7	8.6	2.2	25%	0.1	1%
Canada	35.5	36.7	53.3	(1.2)	(3%)	(16.6)	(31%)
International (14)	120.5	115.2	97.1	5.3	5%	18.1	19%
Total rig years	432.4	405.8	430.9	26.6	7%	(25.1)	(6%)

Rig hours: (15)							
U.S. Land Well-servicing	1,090,511	1,119,497	1,256,141	(28,986)	(3%)	(136,644)	(11%)
Canada Well-servicing	248,032	283,471	360,129	(35,439)	(13%)	(76,658)	(21%)
Total rig hours	1,338,543	1,402,968	1,616,270	(64,425)	(5%)	(213,302)	(13%)

(1) All segment information excludes the Sea Mar business, which has been classified as a discontinued operation.

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

(3) Includes earnings (losses), net from unconsolidated affiliates, accounted for by the equity method, of \$5.8 million, \$5.6 million and \$4.0 million for the years ended December 31, 2008, 2007 and 2006, respectively.

(4) Represents our oil and gas exploration, development and production operations. Includes $228.3 million, representing our proportionate share, of non-cash pre-tax full cost ceiling test writedowns from our U.S., international and Canadian joint ventures and non-cash pre-tax impairment charges of $21.5 million under application of the successful efforts method of accounting from our wholly owned Ramshorn business unit related to oil and gas properties.

(5) Includes earnings (losses), net from unconsolidated affiliates, accounted for by the equity method, of $(241.4) million, $(3.9) million and $0 for the years

ended December 31, 2008, 2007 and 2006, respectively.

(6) The percentage is so large that it is not meaningful.

(7) Includes our drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction and logistics operations.

(8) Includes earnings (losses), net from unconsolidated affiliates, accounted for by the equity method, of $5.8 million, $16.0 million and $16.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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

(10) Adjusted income derived

from operating activities is computed by: subtracting direct costs, general and administrative expenses, depreciation and amortization, and depletion expense from Operating revenues and then adding Earnings from unconsolidated affiliates. Such amounts should not be used as a substitute to those amounts reported under GAAP. 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 income from continuing operations before income taxes, which is a GAAP measure, is provided within the above table.

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

(12) Represents non-cash pre-tax goodwill and intangible asset impairment charges recorded during the three months ended December 31, 2008, all of which related to our Canadian business units.

(13) Excludes well-servicing rigs, which are measured in rig hours. Includes our equivalent percentage ownership of rigs owned by unconsolidated affiliates. Rig years represent 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.

(14) International rig years include our equivalent percentage ownership of rigs owned by unconsolidated affiliates which totaled 3.5 years during the year ended December 31, 2008 and 4.0 years during the years ended December 31, 2007 and 2006, respectively.

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

Segment Results of Operations

Contract Drilling

Our Contract Drilling operating segments contain one or more of the following operations: drilling, workover and well-servicing, on land and offshore.

U.S. Lower 48 Land Drilling. The results of operations for this reportable segment are as follows:

(In thousands, except percentages and rig activity)	Year Ended December 31, 2008	2007	2006	Increase/(Decrease) 2008 to 2007		2007 to 2006	
Operating revenues and Earnings from unconsolidated affiliates	$1,878,441	$1,710,990	$1,890,302	$167,451	10%	$(179,312)	(9%)
Adjusted income derived from operating activities	$ 628,579	$ 596,302	$ 821,821	$ 32,277	5%	$(225,519)	(27%)
Rig years	247.9	229.4	255.5	18.5	8%	(26.1)	(10%)

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The increase in operating results from 2007 to 2008 was due to overall year-over-year increases in rig activity and increases in average dayrates, driven by higher natural gas prices throughout 2007 and most of 2008. This increase was only partially offset by higher operating costs and an increase in depreciation expense related to capital expansion projects.

The decrease in operating results from 2006 to 2007 was a result of year-over-year decreases in drilling activity. Additionally, the decrease in operating results was due to higher drilling rig operating costs, including depreciation expense related to capital expansion projects.

U.S. Land Well-servicing. The results of operations for this reportable segment are as follows:

(In thousands, except percentages and rig activity)	**Year Ended December 31, 2008**	**2007**	**2006**	**Increase/(Decrease) 2008 to 2007**		**2007 to 2006**	
Operating revenues and Earnings from unconsolidated affiliates	$ 758,510	$ 715,414	$ 704,189	$ 43,096	6%	$ 11,225	2%
Adjusted income derived from operating activities	$ 148,626	$ 156,243	$ 199,944	$ (7,617)	(5%)	$ (43,701)	(22%)
Rig hours	1,090,511	1,119,497	1,256,141	(28,986)	(3%)	(136,644)	(11%)

Operating revenues and Earnings from unconsolidated affiliates increased from 2007 to 2008 and from 2006 to 2007 primarily as a result of higher average dayrates year-over-year, driven by high oil prices during 2007 and the majority of 2008 as well as market expansion. Higher average dayrates were partially offset by lower rig utilization. Adjusted income derived from operating activities decreased from 2007 to 2008 and from 2006 to 2007 despite higher revenues due primarily to higher depreciation expense related to capital expansion projects and, to a lesser extent, higher operating costs.

U.S. Offshore. The results of operations for this reportable segment are as follows:

(In thousands, except percentages and rig activity)	**Year Ended December 31, 2008**	**2007**	**2006**	**Increase/(Decrease) 2008 to 2007**		**2007 to 2006**	
Operating revenues and Earnings from unconsolidated affiliates	$252,529	$212,160	$221,676	$40,369	19%	$ (9,516)	(4%)
Adjusted income derived from operating activities	$ 59,179	$ 51,508	$ 65,328	$ 7,671	15%	$(13,820)	(21%)
Rig years	17.6	15.8	16.4	1.8	11%	(0.6)	(4%)

The increase in operating results from 2007 to 2008 primarily resulted from higher average dayrates and increased drilling activity driven by high oil prices during the majority of 2008, especially in the Sundowner and Super Sundowner platform workover and re-drilling rigs and the MASE platform drilling rigs. The increase in 2008 was partially offset by higher operating costs and increased depreciation expense relating to new rigs added to the fleet in early 2007.

The decrease in operating results from 2006 to 2007 primarily resulted from a decrease in average dayrates and utilization for our jack-up rigs, partially offset by the deployment of two new-built Barge and one Platform Workover Drilling rigs in early 2007. Operating results were further negatively impacted by increased depreciation expense relating to the new rigs added to the fleet.

Alaska. The results of operations for this reportable segment are as follows:

(In thousands, except percentages and rig activity)	**Year Ended December 31, 2008**	**2007**	**2006**	**Increase 2008 to 2007**		**2007 to 2006**	
Operating revenues and Earnings from unconsolidated affiliates	$184,243	$152,490	$110,718	$31,753	21%	$41,772	38%
Adjusted income derived from operating activities	$ 52,603	$ 37,394	$ 17,542	$15,209	41%	$19,852	113%
Rig years	10.9	8.7	8.6	2.2	25%	0.1	1%

The increase in operating results from 2007 to 2008 and from 2006 to 2007 is primarily due to year-over-year increases in average dayrates and drilling activity. Drilling activity levels have increased as a result of year-over-year increased customer demand, driven by higher oil prices throughout 2007 and most of 2008, and the deployment and utilization of additional rigs added in late 2007. These increases have been partially offset by higher operating costs and increased depreciation expense as well as increased labor and repairs and maintenance costs in 2008 and 2007 as compared to prior years.

Canada. The results of operations for this reportable segment are as follows:

(In thousands, except percentages and rig activity)	Year Ended December 31, 2008	2007	2006	Increase/(Decrease) 2008 to 2007		2007 to 2006	
Operating revenues and Earnings from unconsolidated affiliates	$502,695	$545,035	$686,889	$(42,340)	(8%)	$(141,854)	(21%)
Adjusted income derived from operating activities	$ 61,040	$ 87,046	$185,117	$(26,006)	(30%)	$ (98,071)	(53%)
Rig years Drilling	35.5	36.7	53.3	(1.2)	(3%)	(16.6)	(31%)
Rig hours Well-servicing	248,032	283,471	360,129	(35,439)	(13%)	(76,658)	(21%)

The decrease in operating results from 2007 to 2008 and from 2006 to 2007 resulted from year-over-year decreases in drilling and well-servicing activity and decreases in average dayrates for drilling and well-servicing operations as a result of economic uncertainty and Alberta s tight labor market resulting in a number of projects being delayed. Our operating results were further negatively impacted by proposed changes to the Alberta royalty and tax regime causing customers to assess the impact of such changes. The strengthening of the Canadian dollar versus the U.S. dollar during 2007 and throughout the majority of 2008 positively impacted operating results, but negatively impacted demand for our services as much of our customers revenue is denominated in U.S. dollars while their costs are denominated in Canadian dollars. Additionally, operating results were negatively impacted by increased operating expenses, including depreciation expense related to capital expansion projects. Operating results exclude non-cash pre-tax goodwill and intangible asset impairment charges that are separately reflected in the Goodwill and Intangible Asset Impairment financial line in our consolidated statements of income.

International. The results of operations for this reportable segment are as follows:

(In thousands, except percentages and rig activity)	Year Ended December 31, 2008	2007	2006	Increase 2008 to 2007		2007 to 2006	
Operating revenues and Earnings from unconsolidated affiliates	$1,372,168	$1,094,802	$746,460	$277,366	25%	$348,342	47%
Adjusted income derived from operating activities	$ 407,675	$ 332,283	$208,705	$ 75,392	23%	$123,578	59%
Rig years	120.5	115.2	97.1	5.3	5%	18.1	19%

The increase in operating results from 2007 to 2008 and from 2006 to 2007 primarily resulted from year-over-year increases in average dayrates and drilling activities, reflecting strong customer demand for drilling services, stemming from sustained higher oil prices throughout 2007 and most of 2008. The increases in operating results during 2007 and 2008 were also positively impacted by an expansion of our rig fleet and continuing renewal of existing multi-year contracts at higher average dayrates. These increases are partially offset by increased operating expenses, including depreciation expense related to capital expenditures for new and refurbished rigs deployed throughout 2007 and 2008.

Oil and Gas

This operating segment represents our oil and gas exploration, development and production operations. The results of operations for this reportable segment are as follows:

(In thousands, except percentages)	Year Ended December 31, 2008	2007	2006	Increase/(Decrease) 2008 to 2007		2007 to 2006	
Operating revenues and Earnings (losses) from unconsolidated affiliates	$(151,465)	$152,320	$59,431	$(303,785)	(199%)	$92,889	156%
Adjusted income derived from operating activities	$(228,027)	$ 56,133	$ 4,065	$(284,160)	(506%)	$52,068	n/m(1)

(1) The percentage is so large that it

is not
meaningful.

Operating results decreased from 2007 to 2008 as a result of non-cash pre-tax impairment charges recorded during the fourth quarter of 2008 by our wholly owned Ramshorn business unit and our U.S., international and Canadian joint ventures. Because of the low natural gas prices at year end, we performed an impairment test on our oil and gas properties of our wholly owned Ramshorn business unit which follows the successful efforts method of accounting. As a result, we recorded a non-cash pre-tax impairment to oil and gas properties which totaled \$21.5 million. Our joint ventures non-cash pre-tax full cost ceiling test writedowns, of which our proportionate share totaled \$228.3 million, resulted from the application of the full cost method of accounting for costs related to oil and natural gas properties. The full cost ceiling test limits the carrying value of the capitalized cost of the properties to the present value of future net revenues attributable to proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or market value of unproved properties. The full cost ceiling test is evaluated at the end of each quarter using quarter end prices of oil and natural gas, adjusted for the impact of derivatives accounted for as cash flow hedges. Our U.S., international and Canadian joint

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ventures used a quarter end price of $5.63 per mcf for natural gas and $44.60 per barrel for oil which resulted in the ceiling test writedowns.

Additionally, our proportionate share of losses from our oil and gas joint ventures included $10.0 million of depletion charges from lower than expected performance of certain oil and gas developmental wells and $5.8 million of mark-to-market unrealized losses from derivative instruments representing forward gas sales through swaps and price floor guarantees utilizing puts. Beginning in May 2008 our U.S. joint venture began to apply hedge accounting to their forward contracts to minimize the volatility in reported earnings caused by market price fluctuations of the underlying hedged commodities. While our wholly owned Ramshorn business unit recorded approximately $21.5 million in non-cash pre-tax impairment charges to oil and gas properties, the charge was partially offset by income from our production volumes and oil and gas production sales as a result of higher oil and natural gas prices throughout most of 2008 and a $12.3 million gain on the sale of certain leasehold interests in 2008.

The increase in our operating results from 2006 to 2007 was primarily a result of year-over-year increases in income attributable to earnings related to production payment contracts and gains totaling $88 million recognized on the sale of certain properties during 2007. Additionally, operating results were higher year-over-year due to increases in production and increases in oil, gas and natural gas liquid prices. These increases to operating results were partially offset by a $33.6 million increase in depletion expense and approximately $3.9 million in net losses from our joint ventures which commenced operations in 2007, as well as higher seismic costs and workover expenses compared to the prior year. The higher depletion expense resulted from increased units-of-production depletion and impairment charges, related to higher costs and lower than expected performance of certain oil and gas developmental wells.

Other Operating Segments

These operations include our drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction and logistics operations. The results of operations for these operating segments are as follows:

	Year Ended December 31,			Increase			
(In thousands, except percentages)	**2008**	**2007**	**2006**	**2008 to 2007**		**2007 to 2006**	
Operating revenues and Earnings from unconsolidated affiliates	$683,186	$588,483	$505,286	$94,703	16%	$83,197	16%
Adjusted income (loss) derived from operating activities	$ 68,572	$ 35,273	$ 30,028	$33,299	94%	$ 5,245	17%

The increase in operating results from 2007 to 2008 and from 2006 to 2007 primarily resulted from year-over-year increased third party sales and higher margins on top drives driven by the strengthening of the oil drilling market and increased equipment sales and increased market share in Canada and increased demand in the U.S. directional drilling market. Results for construction and logistics services increased from 2007 to 2008 due to increases in customer demand for our construction and logistics services in Alaska but decreased from 2006 to 2007 due to lower demand for our services.

Discontinued Operations

During the third quarter of 2007 we sold our Sea Mar business which had previously been included in Other Operating Segments to an unrelated third party. The assets included 20 offshore supply vessels and certain related assets, including a right under a vessel construction contract. The operating results of this business for all periods presented are retroactively presented and accounted for as discontinued operations in the accompanying audited consolidated statements of income**.** Our condensed statements of income from discontinued operations related to the Sea Mar business for the years ended December 31, 2008, 2007 and 2006 were as follows:

	Year Ended December 31,			Increase/(Decrease)			
(In thousands, except percentages)	**2008**	**2007**	**2006**	**2008 to 2007**		**2007 to 2006**	
Revenues	$	$58,887	$112,873	$(58,887)	(100%)	$(53,986)	(48%)
Income from discontinued operations, net of tax	$	$35,024	$ 27,727	$(35,024)	(100%)	$ 7,297	26%

The decrease in revenues from 2006 to 2007 resulted from seven months of operations before our sale of the Sea Mar business in August 2007. The increase in income, net of tax, from 2006 to 2007 resulted from the gain recognized on the sale.

OTHER FINANCIAL INFORMATION

General and administrative expenses

	Year Ended December 31,			Increase/(Decrease)			
(In thousands, except percentages)	2008	2007	2006	2008 to 2007		2007 to 2006	
General and administrative expenses	$479,984	$436,282	$416,610	$43,702	10%	$19,672	5%
General and administrative expenses as a percentage of operating revenues	8.7%	8.8%	8.9%	(.1%)	(1%)	(.1%)	(1%)

General and administrative expenses increased from 2007 to 2008 and from 2006 to 2007 primarily as a result of increases in wages and burden for a majority of our operating segments compared to each prior year period, which resulted from an increase in the number of employees required to support the increase in activity levels and from higher wages, and increased corporate compensation expense, which primarily resulted from higher bonuses and non-cash compensation expenses recorded for restricted stock awards during each sequential year. During the fourth quarter of 2006 a non-recurring non-cash charge representing additional compensation expense of $51.6 million was recorded relating to the Company s review of its employee stock option granting practices.

Depreciation and amortization, and depletion expense

	Year Ended December 31,			Increase/(Decrease)			
(In thousands, except percentages)	2008	2007	2006	2008 to 2007		2007 to 2006	
Depreciation and amortization expense	$611,066	$467,730	$364,653	$143,336	31%	$103,077	28%
Depletion expense	$ 46,979	$ 72,182	$ 38,580	$ (25,203)	(35%)	$ 33,602	87%

Depreciation and amortization expense. Depreciation and amortization expense increased from 2007 to 2008 and from 2006 to 2007 as a result of capital expenditures made throughout 2006, 2007 and 2008 relating to our expanded capital expenditure program that commenced in early 2005.

Depletion expense. The decrease in depletion expense from 2007 to 2008 primarily resulted from a decrease of non-cash impairment charges of $37.9 million during 2007 compared to $21.5 million during 2008.

Depletion expense increased from 2006 to 2007 as a result of increased units-of-production depletion and impairment charges resulting from higher costs and lower than expected performance of certain oil and gas developmental wells.

Interest expense

	Year Ended December 31,			Increase			
(In thousands, except percentages)	2008	2007	2006	2008 to 2007		2007 to 2006	
Interest expense	$91,620	$53,702	$46,586	$37,918	71%	$7,116	15%

Interest expense increased from 2007 to 2008 as a result of the additional interest expense related to our February 2008 and July 2008 issuances of 6.15% senior notes due February 2018 in the amounts of $575 million and $400 million, respectively.

Interest expense increased from 2006 to 2007 as a result of the additional interest expense related to the May 2006 issuance of the $2.75 billion 0.94% senior exchangeable notes due 2011. This increase was partially offset by interest expense reductions resulting from the redemption of 93% or $769.8 million of our zero coupon convertible senior debentures due 2021 on February 6, 2006. These zero coupon notes accreted at a rate of 2.5% per annum.

Investment income (loss)

	Year Ended December 31,			Increase/(Decrease)			
(In thousands, except percentages)	2008	2007	2006	2008 to 2007		2007 to 2006	
Investment income (loss)	$21,726	$(15,891)	$102,007	$37,617	237%	$(117,898)	(116%)

Investment income during 2008 was $21.7 million compared to a net loss of $15.9 million during the prior year. The current year income included net unrealized gains of $8.5 million from our trading securities and interest and dividend income of $40.5 million from our short-term and long-term investments, partially offset by losses of $27.4 million from our actively managed funds classified as long-term investments.

Investment income (loss) during 2007 was a net loss of $15.9 million compared to income of $102.0 million during the prior year. The loss during 2007 included a net loss of $61.4 million from the portion of our long-term investments comprised of actively

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managed funds inclusive of substantial gains from sales of our marketable equity securities. Investment income from our short-term investments was approximately $45.5 million.

Investment income during 2006 included net unrealized gains of $3.1 million from our short-term investments, interest and dividend income of $55.7 million and gains of $43.2 million from our actively managed funds.

Gains (losses) on sales, retirements and impairments of long-lived assets and other income (expense), net

	Year Ended December 31,			Increase/(Decrease)			
(In thousands, except percentages)	**2008**	**2007**	**2006**	**2008 to 2007**		**2007 to 2006**	
Gains (losses) on sales, retirements and impairments of long-lived assets and other income (expense), net	$(7,613)	$(10,895)	$(24,118)	$3,282	30%	$13,223	55%

The amount of gains (losses) on sales, retirements and impairments of long-lived assets and other income (expense), net for 2008 represents a net loss of $7.6 million and includes: (1) losses on derivative instruments of approximately $14.6 million, including a $9.9 million loss on a three-month written put option and a $4.7 million loss on the fair value of our range cap and floor derivative, (2) losses on retirements and impairment charges on long-lived assets of approximately $13.2 million, inclusive of involuntary conversion losses on long-lived assets of approximately $12.0 million, net of insurance recoveries, related to damage sustained from Hurricanes Gustav and Ike during 2008, and (3) losses resulting from increases to litigation reserves of $3.5 million. These losses were partially offset by a $23.6 million pre-tax gain recognized on our purchase of $100 million par value of our $2.75 billion 0.94% senior exchangeable notes due 2011.

The amount of gains (losses) on sales, retirements and impairments of long-lived assets and other income (expense), net for 2007 represents a net loss of $10.9 million and includes: (1) losses on retirements and impairment charges on long-lived assets of approximately $40.0 million and (2) losses resulting from increases to litigation reserves of $9.6 million. These losses were partially offset by the $38.6 million gain on the sale of three accommodation jack-up rigs in the second quarter of 2007.

Goodwill and intangible asset impairment

	Year Ended December 31,		
(In thousands, except percentages)	**2008**	**2007**	**2006**
Goodwill and intangible asset impairment	$154,586		

Our goodwill impairment for the year ended December 31, 2008 is comprised of $145.4 million and $4.6 million, respectively, relating to our Canada Well-servicing and Drilling operating segment and Nabors Blue Sky Ltd., one of our Canadian subsidiaries reported in our Other Operating Segments. The non-cash impairment charges were determined necessary due to the duration of the economic downturn in Canada and the lack of certainty regarding eventual recovery in valuing these operations. Additionally, we recorded a non-cash impairment to intangible assets of $4.6 million which related to certain rights and licenses for a helicopter by Blue Sky, Ltd. A prolonged period of lower oil and natural gas prices and its potential impact on our financial results could result in future goodwill impairment charges. See Critical Accounting Policies below and Note 2 (included under the caption Goodwill) in Part II, Item 8. Financial Statements and Supplementary Data.

Income tax rate

	Year Ended December 31,		
	2008	**2007**	**2006**
Effective income tax rate from continuing operations	31%	21%	30%

The increase in our effective income tax rate from 2007 to 2008 resulted from (1) our goodwill impairments that had no associated tax benefit, (2) the reversal of certain tax reserves during 2007 in the amount of $25.5 million, (3) a decrease in 2007 tax expense of approximately $16.0 million resulting from a reduction in Canada s tax rate, and (4) a higher proportion of our taxable income being generated in the United States during 2008 which is generally taxed at a higher rate than in the international jurisdictions in which we operate.

The decrease in our effective income tax rate from 2006 to 2007 is a direct result of (1) the reversal of certain tax reserves during 2007 in the amount of $25.5 million, (2) a decrease in tax expense of approximately $16.0 million resulting from a reduction in Canadian tax rates, and (3) a decrease in the proportion of income generated in the U.S. versus the international jurisdictions in which we operate. During 2006, a tax expense relating to the redemption of common shares held by a foreign parent of a U.S. based Nabors subsidiary in the amount of $36.2 million increased taxes while a reduction in Canadian tax rates decreased tax expense in the amount of $20.5 million.

Significant judgment is required in determining our worldwide provision for income taxes. In the ordinary course of our business, there are many transactions and calculations where the ultimate tax determination is uncertain. We are regularly under audit by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than that which is reflected in our income tax provisions and accruals. Based on the results of an audit or litigation, a material effect on our financial position, income tax provision, net income, or cash flows in the period or periods for which that determination is made could result.

Various bills have been introduced in Congress which could reduce or eliminate the tax benefits associated with our reorganization as a Bermuda company. Legislation enacted by Congress in 2004 provides that a corporation that reorganized in a foreign jurisdiction on or after March 4, 2003 shall be treated as a domestic corporation for United States federal income tax purposes. Nabors reorganization was completed June 24, 2002. There has been and we expect that there may continue to be legislation proposed by Congress from time to time applicable to certain companies that completed such reorganizations on or after March 20, 2002 which, if enacted, could limit or eliminate the tax benefits associated with our reorganization.

Because we cannot predict whether legislation will ultimately be adopted, no assurance can be given that the tax benefits associated with our reorganization will ultimately accrue to the benefit of the Company and its shareholders. It is possible that future changes to the tax laws (including tax treaties) could have an impact on our ability to realize the tax savings recorded to date as well as future tax savings resulting from our reorganization.

We expect our effective tax rate during 2009 to be in the 25-28% range. We are subject to income taxes in the U.S. and numerous foreign jurisdictions. One of the most volatile factors in this determination is the relative proportion of our income being recognized in high versus low tax jurisdictions.

Liquidity and Capital Resources

Cash Flows

Our cash flows depend, to a large degree, on the level of spending by oil and gas companies for exploration, development and production activities. Sustained increases or decreases in the price of natural gas or oil could have a material impact on these activities, and could also materially affect our cash flows. Certain sources and uses of cash, such as the level of discretionary capital expenditures, purchases and sales of investments, issuances and repurchases of debt and of our common shares are within our control and are adjusted as necessary based on market conditions. The following is a discussion of our cash flows for the years ended December 31, 2008 and 2007.

Operating Activities. Net cash provided by operating activities totaled $1.4 billion during 2008 compared to net cash provided by operating activities of $1.4 billion during 2007. During 2008, net income was increased for non-cash items, such as depreciation and amortization, depletion, share-based compensation, deferred income taxes, our proportionate share of losses from unconsolidated affiliates and goodwill and intangible asset impairments and was reduced for changes in our working capital and other balance sheet accounts. During 2007, net income was increased for non-cash items, such as depreciation and amortization, depletion, share-based compensation and was reduced for deferred income taxes, changes in our working capital and other balance sheet accounts.

Investing Activities. Net cash used for investing activities totaled $1.4 billion during 2008 compared to net cash used for investing activities of $1.5 billion during 2007. During 2008 and 2007, cash was used for capital expenditures totaling $1.5 billion and $2.0 billion, respectively, and investment in unconsolidated affiliates totaling $271.3 million and $278.1 million, respectively. During 2008 and 2007, cash was provided by sales of investments, net of purchases, totaling $251.6 million and $482.1 million, respectively. During 2007, cash was provided from the sale of long-lived assets and from the sale of our Sea Mar business totaling $162.1 million and $194.3 million, respectively.

Financing Activities. Net cash used for financing activities totaled $89.2 million during 2008 compared to net cash used for financing activities of $78.9 million during 2007. During 2008, cash totaling $836.5 million was used to redeem our $700 million zero coupon senior exchangeable notes due 2023 and our $82.8 million zero coupon senior convertible debentures due 2021 and for the purchase of $100 million par value of our $2.75 billion 0.94% senior exchangeable notes due 2011 in the open market. During 2008 and 2007, cash was used to repurchase our common shares totaling $281.1 million and $102.5 million, respectively. During 2008, cash was provided by the receipt of $955.6 million in proceeds, net of debt issuance costs, from the February and July 2008 issuances of our $575 million and $400 million 6.15% senior notes due 2018, respectively. During 2008 and 2007, cash was provided by our receipt of proceeds totaling $56.6 million and $61.6 million, respectively, from the exercise by our employees of options to acquire our common shares.

Future Cash Requirements

As of December 31, 2008, we had long-term debt, including current maturities, of $4.1 billion and cash and cash equivalents and investments of $826.1 million, including $240.0 million of long-term investments and other receivables. Long-term investments and other receivables include $224.2 million in oil and gas financing receivables.

Our $225 million 4.875% senior notes are coming due in August 2009 and have been reclassified from long-term debt to current portion of long-term debt in our balance sheet as of September 30, 2008. During January and through February 23, 2009, we repurchased $56.6 million par value of these senior notes for cash totaling $56.8 million.

Our $2.75 billion 0.94% senior exchangeable notes due 2011 provide that upon an exchange of these notes, we will be required to pay holders of the notes cash up to the principal amount of the notes and our common shares for any amount that the exchange value of the notes exceeds the principal amount of the notes. The notes cannot be exchanged until the price of our shares exceeds approximately $59.57 for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the previous calendar quarter; or during the five business days immediately following any ten consecutive trading day period in which the trading price per note for each day of that period was less than 95% of the product of the sale price of Nabors common shares and the then applicable exchange rate for the notes; or upon the occurrence of specified corporate transactions set forth in the indenture. On February 23, 2009, the market price for our shares closed at $9.14. If any of the events described above were to occur and the notes were exchanged at a purchase price equal to 100% of the principal amount of the notes, the required cash payment could have a significant impact on our level of cash and cash equivalents and investments available to meet our other cash obligations. Management believes that in the event that the price of our shares were to exceed $59.57 for the required period of time that the holders of these notes would not be likely to exchange the notes as it would be more economically beneficial to them if they sold the notes to other investors on the open market. However, there can be no assurance that the holders would not exchange the notes.

During the fourth quarter of 2008 we purchased $100 million par value of our $2.75 billion 0.94% senior exchangeable notes due 2011 in the open market, leaving $2.65 billion par value outstanding at December 31, 2008. In January and through February 23, 2009, we purchased an additional $427.7 million par value of our $2.75 billion 0.94% senior exchangeable notes due 2011 in the open market for cash totaling $370.6 million, leaving $2.22 billion par value outstanding.

As of December 31, 2008, we had outstanding purchase commitments of approximately $685.3 million, primarily for rig-related enhancing, construction and sustaining capital expenditures and other operating expenses. Total capital expenditures over the next twelve months, including these outstanding purchase commitments, are currently expected to be approximately $1.0-1.2 billion, including currently planned rig-related enhancing, construction and sustaining capital expenditures. This amount could change significantly based on market conditions and new business opportunities. The level of our outstanding purchase commitments and our expected level of capital expenditures over the next twelve months represent a number of capital programs that are currently underway or planned. These programs have resulted in an expansion in the number of drilling and well-servicing rigs that we own and operate and consist primarily of land drilling and well-servicing rigs. Since expanding our capital expenditure program in 2005, we have added 168 new land drilling rigs, 15 offshore rigs and 116 newly built workover and well-servicing rigs to our fleet. Our expansion of our capital expenditure programs to build new state-of-the-art drilling rigs is expected to impact a majority of our operating segments, most significantly within our U.S. Lower 48 Land Drilling, U.S. Land Well-servicing, Alaska, Canada and International operations.

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

See our discussion of guarantees issued by Nabors that could have a potential impact on our financial position, results of operations or cash flows in future periods included under Off-Balance Sheet Arrangements (Including Guarantees).

The following table summarizes our contractual cash obligations as of December 31, 2008. This table does not include the issue of $1.125 billion 9.25% senior notes due 2019 on January 12, 2009 nor any open market purchases of any of our notes that have occurred since December 31, 2008.

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			Payments due by Period			
(In thousands)	**Total**	**< 1 Year**	**1-3 Years**	**3-5 Years**	**Thereafter**	**Other**
Contractual cash obligations:						
Long-term debt: (1)						
Principal	$4,126,008	$ 225,288(2)	$2,650,553(3)	$275,167(4)	$ 975,000(5)	$
Interest	702,235	110,683	186,961	134,760	269,831	
Operating leases (6)	46,254	20,209	16,869	4,887	4,289	
Purchase commitments (7)	685,293	681,922	3,371			
Employment contracts (6)	22,225	6,906	10,525	4,794		
Pension funding obligations (8)	750	750				
Tax reserves (9)	70,447					70,447
Total contractual cash obligations	$5,653,212	$1,045,758	$2,868,279	$419,608	$1,249,120	$70,447

(1) See Note 10 in Part II, Item 8. Financial Statements and Supplementary Data.

(2) Represents Nabors Holdings $225 million 4.875% senior notes due August 2009. In January and through February 23, 2009, we repurchased $56.6 million par value of our $225 million principal amount of 4.875% senior notes due

August 2009 in the open market for cash totaling $56.8 million.

(3) Includes Nabors Delaware s $2.75 billion 0.94% senior exchangeable notes due May 2011. In 2008 we purchased $100 million par value of these notes in the open market, leaving $2.65 billion par value outstanding at December 31, 2008. During January and through February 23, 2009, we purchased an additional $427.7 million par value of these notes in the open market for cash totaling $370.6 million.

(4) Includes Nabors Delaware s $275 million 5.375% senior notes due August 2012.

(5) Represents Nabors Delaware s aggregate $975 million 6.15% senior notes due February 2018.

(6) See Note 15 in Part II, Item 8. Financial Statements and Supplementary Data.

(7) Purchase commitments include agreements to purchase goods or services that are enforceable and legally binding and that specify all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable pricing provisions; and the approximate timing of the transaction.

(8) See Note 13 in Part II, Item 8. Financial Statements and Supplementary Data.

(9) Tax reserves are included in Other due to the difficulty in making reasonably reliable estimates of the timing of cash settlements to taxing authorities. See

Note 11 in
Part II, Item 8.
Financial
Statements and
Supplementary
Data.

We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

In July 2006 our Board of Directors authorized a share repurchase program under which we may repurchase up to $500 million of our common shares in the open market or in privately negotiated transactions. This program supersedes and cancels our previous share repurchase program. Through December 31, 2008, $464.5 million of our common shares had been repurchased under this program. As of December 31, 2008, we had the capacity to repurchase up to an additional $35.5 million of our common shares under the July 2006 share repurchase program.

See Note 15 in Part II, Item 8. Financial Statements and Supplementary Data for discussion of commitments and contingencies relating to (i) employment contracts that could result in significant cash payments of $264 million and $90 million to Messrs. Isenberg and Petrello, respectively, by the Company if there are terminations of these executives in the event of death, disability, termination without cause or cash payments of $360 million and $122 million to Messrs. Isenberg and Petrello, respectively, by the Company if there are terminations of these executives in the event of a change in control, inclusive of gross up payments, and (ii) off-balance sheet arrangements (including guarantees).

Financial Condition and Sources of Liquidity

Our primary sources of liquidity are cash and cash equivalents, short-term and long-term investments and cash generated from operations. As of December 31, 2008, we had cash and cash equivalents and investments of $826.1 million (including $240.0 million of long-term investments and other receivables, inclusive of $224.2 million in oil and gas financing receivables) and working capital of $1.0 billion. Oil and gas financing receivables are classified as long-term investments. These receivables represent our financing agreements for certain production payment contracts in our Oil and Gas segment. Long-term investments also consist of investments in overseas funds investing primarily in a variety of public and private U.S. and non-U.S. securities (including asset-backed securities and mortgage-backed securities, global structured asset securitizations, whole loan mortgages, and participations in whole loans and whole loan mortgages). These investments are classified as non-marketable, because they do not have published fair values. This compares to cash and cash equivalents and investments of $1.2 billion (including $359.5 million of long-term investments and other receivables, inclusive of $123.3 million in oil and gas financing receivables) and working capital of $711.0 million as of December 31, 2007.

Our gross funded debt to capital ratio was 0.44:1 as of December 31, 2008 and 2007. Our net funded debt to capital ratio was 0.39:1 as of December 31, 2008 and 0.36:1 as of December 31, 2007. The gross funded debt to capital ratio is calculated by dividing funded debt by funded debt plus deferred tax liabilities net of deferred tax assets plus capital. Funded debt is defined as the sum of (1) short-term borrowings, (2) current portion of long-term debt and (3) long-term debt. Capital is defined as shareholders equity. The net funded debt to capital ratio is calculated by dividing net funded debt by net funded debt plus deferred tax liabilities net of deferred tax assets 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 reduced by the sum of cash and cash equivalents and short-term and long-term investments and other receivables. Capital is defined as shareholders equity. Both of these ratios are a method for calculating the amount of leverage a company has in relation to its capital. The gross funded debt to capital ratio and the net funded debt to capital ratio are not measures of operating performance or liquidity defined by GAAP and therefore, they may not be comparable to similarly titled measures presented by other companies.

Our interest coverage ratio from continuing operations was 20.9:1 as of December 31, 2008, compared to 32.5:1 as of December 31, 2007. The interest coverage ratio is a trailing twelve-month computation of the sum of income from continuing operations before income taxes, interest expense, depreciation and amortization, depletion expense, goodwill and intangible asset impairments and our proportionate share of non-cash pre-tax full cost ceiling writedowns from our oil and gas joint ventures less investment income and then dividing by interest expense. This ratio is a method for calculating the amount of operating cash flows available to cover interest expense. The interest coverage ratio from continuing operations is not a measure of operating performance or liquidity defined by GAAP and may not be comparable to similarly titled measures presented by other companies.

We have four letter of credit facilities with various banks as of December 31, 2008. Availability and borrowings under our credit facilities as of December 31, 2008 are as follows:

(In thousands)	
Credit available	$ 295,045
Letters of credit outstanding	174,156
Remaining availability	$ 120,889

On January 12, 2009, Nabors Delaware completed a private placement of $1.125 billion aggregate principal amount of 9.25% senior notes due 2019 with registration rights, which are unsecured and are fully and unconditionally guaranteed by Nabors Bermuda. Nabors Delaware intends to use the proceeds from the offering for the repayment or repurchase of indebtedness and general corporate purposes.

Our ability to access capital markets or to otherwise obtain sufficient financing is enhanced by our senior unsecured debt ratings as provided by DBRS, Fitch Ratings, Moody s Investor Service and Standard & Poor s, which are currently BBB+ , BBB+ , Baa1 and BBB+ (Negative Watch) , respectively, and our historical ability to access the markets as needed. However, recent instability in the global financial markets has resulted in a significant reduction in the availability of funds from capital markets and other credit markets and as a result, our ability to access these markets at this time may be significantly reduced. In addition, Standard & Poor s recently affirmed its BBB+ credit rating, but revised its outlook to negative from stable due primarily to worsening industry conditions. A credit downgrade by Standard & Poor s may impact our ability to access credit markets.

Our current cash and cash equivalents, investments and projected cash flows generated from current operations are expected to adequately finance our purchase commitments, our scheduled debt service requirements, and all other expected cash requirements for the next twelve months.

See our discussion of the impact of changes in market conditions on our derivative financial instruments discussed under Item 7A. Quantitative and Qualitative Disclosures About Market Risk on page 40.

Off-Balance Sheet Arrangements (Including Guarantees)

We are a party to certain transactions, agreements or other contractual arrangements defined as off-balance sheet arrangements that could have a material future effect on our financial position, results of operations, liquidity and capital resources. The most significant of these off-balance sheet arrangements involve agreements and obligations in which we provide financial or performance assurance to third parties. Certain of these agreements serve as guarantees, including standby letters of credit issued on behalf of insurance carriers in conjunction with our workers compensation insurance program and other financial surety instruments such as bonds. We have also guaranteed payment of contingent consideration in conjunction with an acquisition in 2005. Potential contingent consideration is based on future operating results of the acquired business. In addition, we have provided indemnifications to certain third parties which serve as guarantees. These guarantees include indemnification provided by Nabors to our share transfer agent and our insurance carriers. We are not able to estimate the potential future maximum payments that might be due under our indemnification guarantees.

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

	Maximum Amount				
(In thousands)	**2009**	**2010**	**2011**	**Thereafter**	**Total**
Financial standby letters of credit and other financial surety instruments	$ 143,444	$ 12,277	$ 965	$	$ 156,686
Contingent consideration in acquisition		2,125	2,125		4,250
Total	$ 143,444	$ 14,402	$ 3,090	$	$ 160,936

Other Matters

Recent Legislation and Actions

In February 2009 Congress enacted the American Recovery and Reinvestment Act of 2009 (the Stimulus Act). The Stimulus Act is intended to provide a stimulus to the U.S. economy, including relief to companies related to income on debt repurchases and exchanges at a discount, expansion of benefits to former employees and other social welfare provisions. We are currently evaluating the impact that the Stimulus Act may have on our consolidated financial statements.

A court in Algeria has entered a judgment against the Company related to certain alleged customs infractions. The Company believes it did not receive proper notice of the judicial proceedings against it, and that the amount of the judgment is excessive. We intend to assert the lack of legally required notice as a basis for challenging the judgment on appeal. Based upon our understanding of applicable law and precedent, we believe that this challenge will be successful. We do not believe that a loss is probable and have not accrued any amounts related to this matter. However, the ultimate resolution of this matter, and the timing of such resolution, is uncertain. If the Company is ultimately required to pay a fine or judgment related to this matter, the amount of the loss could range from approximately $140,000 to $20 million.

Recent Accounting Pronouncements

In December 2007 the FASB issued Statement of Financial Accounting Standards (SFAS) No. 141(R), Business Combinations. This statement retains the fundamental requirements in SFAS No. 141, Business Combinations that the acquisition method of accounting be used for all business combinations and expands the same method of accounting to all transactions and other events in which one entity obtains control over one or more other businesses or assets at the acquisition date and in subsequent periods. This statement replaces SFAS No. 141 by requiring measurement at the acquisition date of the fair value of assets acquired, liabilities assumed and any noncontrolling interest. Additionally, SFAS No. 141(R) requires that acquisition-related costs, including restructuring costs, be recognized as expense separately from the acquisition. SFAS No. 141(R) applies prospectively to business combinations for fiscal years beginning after December 15, 2008. We will adopt SFAS No. 141(R) beginning January 1, 2009 and apply to future acquisitions.

In December 2007 the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51. This statement establishes the accounting and reporting standards for a noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests and applies prospectively to business combinations for fiscal years beginning after December 15, 2008. We will adopt SFAS No. 160 beginning January 1, 2009. We are currently evaluating the impact that this pronouncement may have on our consolidated financial statements.

In September 2006 the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements for financial assets and liabilities, as well as for any other assets and liabilities that are carried at fair value on a recurring basis in financial statements. SFAS No. 157 is effective with respect to financial assets and liabilities for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. SFAS No. 157 applies prospectively to financial assets and liabilities. There is a one year deferral for the implementation of SFAS No. 157 for nonfinancial assets and liabilities measured on a nonrecurring basis. Effective January 1, 2008, we adopted the provisions of SFAS No. 157 relating to financial assets and liabilities. The new disclosures regarding the level of pricing observability associated with financial instruments carried at fair value is provided in Note 3 in Part II, Item 8. Financial Statements and Supplementary Data. The adoption of SFAS No. 157 with respect to financial assets and liabilities did not have a material financial impact on our consolidated results of operations or financial condition. We are currently evaluating the impact of implementation with respect to nonfinancial assets and liabilities measured on a nonrecurring basis on our consolidated financial statements, which will be primarily limited to asset impairments including goodwill, intangible assets and other long-lived assets, assets acquired and liabilities assumed in a business combination and asset retirement obligations.

In October 2008 the FASB issued Staff Position (FSP) SFAS No. 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active. This FSP clarifies the application of SFAS No. 157 in an inactive market and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP was effective October 10, 2008 and must be applied to prior periods for which financial statements have not been issued. The application of this FSP did not have a material impact on our consolidated financial statements.

In February 2007 the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115. This statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value and establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007, provided the entity also elects to apply the provisions of SFAS No. 157. The adoption of SFAS No. 159 did not have a material impact on our consolidated results of operations or financial condition as we have not elected to apply the provisions to our financial instruments or other eligible items that are not currently required to be measured at fair value.

In March 2008 the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment to FASB Statement No. 133. This statement is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced qualitative and quantitative disclosures regarding derivative instruments, gains and losses on such instruments and their effects on an entity s financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. We are currently evaluating the impact that this pronouncement may have on our consolidated financial statements.

In May 2008 the FASB issued FSP APB No. 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement). The FSP clarifies the position that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants. The FSP requires that convertible debt instruments be accounted for with a liability component based on the fair value of a similar nonconvertible debt instrument and an equity component based on the excess of the initial proceeds from the convertible debt instrument over the liability component. Such excess represents a debt discount which is then amortized as additional non-cash interest expense over the convertible debt instrument s expected life. The FSP will be effective for Nabors financial statements issued for fiscal years and interim periods beginning after December 15, 2008, and will be applied retrospectively to all convertible debt instruments within its scope that are outstanding for any period presented in such financial statements. We will adopt the FSP on January 1, 2009 on a retrospective basis and apply it to our applicable convertible debt instruments. We expect that the impact of this FSP on our financial statements will be to reduce our long-term debt balance and increase our shareholders equity in our consolidated balance sheets for each period presented and will result in a non-cash increase to our previously reported interest expense of approximately $100 million and $110 million for the years ended December 31, 2007 and 2008, respectively, in our consolidated statements of income. We also expect that the retrospective application of the FSP will reduce reported net income by approximately $60-70 million and $70-80 million, respectively, for the years ended December 31, 2007 and 2008. In addition, net income and diluted earnings per share is expected to be materially reduced in future years in which the $2.75 billion senior exchangeable notes due May 2011 issued by Nabors Delaware are outstanding. After adopting this FSP, we currently estimate that we will record additional non-cash interest expense, net of capitalized interest, which will reduce our pre-tax income by approximately $75-85 million and reduce net income by approximately $45-55 million for the year ended December 31, 2009.

In June 2008 the FASB issued FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. This FSP provides that securities which are granted in share-based transactions are participating securities prior to vesting if they have a nonforfeitable right to participate in any dividends, and, such securities therefore, should be included in computing basic earnings per share. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and all prior period earnings per share data should be adjusted retrospectively to conform with the provisions of this FSP. We are currently evaluating the impact that this FSP may have on our consolidated financial statements.

In December 2008 the SEC issued a Final Rule, Modernization of Oil and Gas Reporting . This Final Rule revises certain oil and gas reporting disclosure in Regulation S-K and Regulation S-X under the Securities Act and the Exchange Act, as well as Industry

Guide 2. The amendments are designed to modernize and update oil and gas disclosure requirements to align them with current practices and changes in technology. Additionally, this new accounting standard requires that entities use a trailing twelve month average natural gas and oil price when performing the full cost ceiling test calculation which will impact the accounting by our oil and gas joint ventures. The disclosure requirements are effective for registration statements filed on or after January 1, 2009 and for annual financial statements filed on or after December 31, 2009. We are currently evaluating the impact that this Final Rule may have on our consolidated financial statements.

In December 2008 the FASB issued FSP SFAS No. 140-4 and FIN 46(R)-8, Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities. This FSP increases disclosure requirements for public companies by amending SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities to require additional information about a transferors continuing involvement with transferred financial assets and amending FASB Interpretation No. 46(R) (FIN 46(R)), Consolidation of Variable Interest Entities to require additional disclosure about their involvement with variable interest entities. This FSP is effective for reporting periods that end after December 15, 2008. The new disclosures requirements did not have an impact on our financial statements.

In January 2009 the FASB issued FSP EITF 99-20-a, Amendments to the Impairment and Interest Income Measurement Guidance of EITF Issue No. 99-20. This FSP amends EITF Issue No. 99-20, Recognition of Interest Income and Impairment on Purchased Beneficial Interests and Beneficial Interests That Continue to Be Held by a Transferor in Securitized Financial Assets and applies to the evaluation of impairment of beneficial interests in securitized financial assets. The amendment requires that other-than-temporary impairments be recognized when there has been a probable adverse change in estimated cash flows and removes the references to a market participant view of determining estimated cash flows. This FSP is effective for reporting periods that end after December 15, 2008. The adoption of this FSP did not have a significant impact on our financial statements.

Related-Party Transactions

Pursuant to their employment agreements, Nabors and its Chairman and Chief Executive Officer, Deputy Chairman, President and Chief Operating Officer, and certain other key employees entered into split-dollar life insurance agreements pursuant to which we paid a portion of the premiums under life insurance policies with respect to these individuals and, in certain instances, members of their families. Under these agreements, we are reimbursed for such premiums upon the occurrence of specified events, including the death of an insured individual. Any recovery of premiums paid by Nabors could potentially be limited to the cash surrender value of these policies under certain circumstances. As such, the values of these policies are recorded at their respective cash surrender values in our consolidated balance sheets. We have made premium payments to date totaling $11.2 million related to these policies. The cash surrender value of these policies of approximately $8.4 million and $10.5 million is included in other long-term assets in our consolidated balance sheets as of December 31, 2008 and 2007, respectively.

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

In the ordinary course of business, we enter into various rig leases, rig transportation and related oilfield services agreements with our unconsolidated affiliates at market prices. Revenues from business transactions with these affiliated entities totaled $259.3 million, $153.4 million and $99.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. Expenses from business transactions with these affiliated entities totaled $9.6 million, $6.6 million and $4.7 million for the years ended December 31, 2008, 2007 and 2006, respectively. Additionally, we had accounts receivable from these affiliated entities of $96.1 million and $62.3 million as of December 31, 2008 and 2007, respectively. We had accounts payable to these affiliated entities of $10.0 million and $14.7 million as of December 31, 2008 and 2007, respectively, and long-term payables with these affiliated entities of $7.8 million and $7.8 million as of December 31, 2008 and 2007, respectively, which is included in other long-term liabilities.

During the fourth quarter of 2006, the Company entered into a transaction with Shona Energy Company, LLC (Shona), a company in which Mr. Payne, an outside director of the Company, is the Chairman and Chief Executive

Officer. During the fourth quarter of 2008, the Company purchased 1.8 million common shares of Shona for $.9 million. Pursuant to these transactions, a subsidiary of the Company acquired and holds a minority interest of less than 20% of the issued and outstanding common shares of Shona.

Critical Accounting Estimates

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

- it requires assumptions to be made that were uncertain at the time the estimate was made; and

- changes in the estimate or different estimates that could have been selected could have a material impact on our consolidated financial position or results of operations.

For a summary of all of our significant accounting policies, see Note 2 in Part II, Item 8. - Financial Statements and Supplementary Data.

Financial Instruments. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best information available. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The use of unobservable inputs is intended to allow for fair value determinations in situations in which there is little, if any, market activity for the asset or liability at the measurement date. We are able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a fair value hierarchy such that Level 1 measurements include unadjusted quoted market prices for identical assets or liabilities in an active market, Level 2 measurements include quoted market prices for identical assets or liabilities in an active market which have been adjusted for effects of restrictions and those that are not quoted but are observable through corroboration with observable market data, including quoted market prices for similar assets, and Level 3 measurements include those that are unobservable and of a highly subjective measure.

As part of adopting SFAS No. 157, we did not have a transition adjustment to our retained earnings. Our enhanced disclosures are included in Note 3 in Part II, Item 8. Financial Statements and Supplementary Data.

Depreciation of Property, Plant and Equipment. The drilling, workover and well-servicing industries are very capital intensive. Property, plant and equipment represented 70% of our total assets as of December 31, 2008, and depreciation constituted 14% of our total costs and other deductions for the year ended December 31, 2008.

Depreciation for our primary operating assets, drilling and workover rigs is calculated based on 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 typically used.

Depreciation on our buildings, well-servicing rigs, oilfield hauling and mobile equipment, marine transportation and supply vessels, aircraft equipment, and other machinery and equipment is computed using the straight-line method over the estimated useful life of the asset after provision for salvage value (buildings 10 to 30 years; well-servicing rigs 3 to 15 years; marine transportation and supply vessels 10 to 25 years; aircraft equipment 5 to 20 years; oilfield hauling and mobile equipment and other machinery and equipment 3 to 10 years).

These depreciation periods and the salvage values of our property, plant and equipment were determined through an analysis of the useful lives of our assets and based on our experience with the salvage values of these assets. Periodically, we review our depreciation periods and salvage values for reasonableness given current conditions. Depreciation of property, plant and equipment is therefore based upon estimates of the useful lives and salvage value of those assets. Estimation of these items requires significant management judgment. Accordingly, management believes that accounting estimates related to depreciation expense recorded on property, plant and equipment are critical.

There have been no factors related to the performance of our portfolio of assets, changes in technology or other factors that indicate that these lives do not continue to be appropriate. Accordingly, for the years ended December 31, 2008, 2007 and 2006, no significant changes have been made to the depreciation rates applied to property, plant and equipment, the underlying assumptions related to estimates of depreciation, or the methodology applied. However, certain events could occur that would materially affect our estimates and assumptions related to depreciation. Unforeseen changes in operations or technology could substantially alter management s assumptions regarding our ability to realize the return on our investment in operating assets and therefore affect the useful lives and salvage values of our assets.

Impairment of Long-Lived Assets. As discussed above, the drilling, workover and well-servicing industries are very capital intensive, which is evident in the fact that our property, plant and equipment represented 70% of our total assets as of December 31, 2008. We review our long-lived assets for impairment when events or changes in circumstances indicate that the carrying amounts of such assets may not be recoverable, as required by SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Asset. An impairment loss is recorded in the period in which it is determined that the carrying amount of the long-lived asset is not recoverable. Such determination requires us to make judgments regarding long-term forecasts of future revenues and costs related to the assets subject to review in order to determine the future cash flows associated with the assets. These long-term forecasts are uncertain in that they require assumptions about demand for our products and services, future market conditions, technological advances in the industry, and changes in regulations governing the industry. Significant and unanticipated changes to the assumptions could require a provision for impairment in a future period. As the determination of whether impairment charges should be recorded on our long-lived assets is subject to significant management judgment and an impairment of these assets could result in a material charge on our consolidated statements of income, management believes that accounting estimates related to impairment of long-lived assets are critical.

Assumptions made in the determination of future cash flows are made with the involvement of management personnel at the operational level where the most specific knowledge of market conditions and other operating factors exists. For the years ended December 31, 2008, 2007 and 2006, no significant changes have been made to the methodology utilized to determine future cash flows.

Given the nature of the evaluation of future cash flows and the application to specific assets and specific times, it is not possible to reasonably quantify the impact of changes in these assumptions.

Impairment of Goodwill and Intangible Assets. Other long-lived assets subject to impairment consist primarily of goodwill, which represented 1.7% of our total assets as of December 31, 2008. We review goodwill and intangible assets with indefinite lives for impairment annually or more frequently if events or changes in circumstances indicate that the carrying amount of such goodwill and intangible assets exceed their fair value, as required by SFAS No. 142, Goodwill and Other Intangible Assets. We perform our impairment tests of goodwill and intangible assets for ten reporting units within our operating segments. These reporting units consist of our six contract drilling segments: U.S. Lower 48 Land Drilling, U.S. Land Well-servicing, U.S. Offshore, Alaska, Canada and International and four of our other operating segments: Canrig Drilling Technology Ltd., Epoch Well Services, Inc., Ryan Energy Technologies and Nabors Blue Sky Ltd. The impairment test involves comparing the estimated fair value of goodwill and intangible assets at each reporting unit to its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, a second step is required to measure the goodwill impairment loss. This second step compares the implied fair value of the reporting unit s goodwill to the carrying amount of that goodwill. If the carrying amount of the reporting unit s goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess.

The fair values calculated in these impairment tests are determined using discounted cash flow models involving assumptions based on our utilization of rigs, revenues, earnings from affiliates as well as direct costs, general and administrative costs, depreciation, applicable income taxes, capital expenditures and working capital requirements. Our discounted cash flow projections for each reporting unit were based on financial forecasts. The future cash flows were discounted to present value using discount rates that are determined to be appropriate for each reporting unit. Terminal values for each reporting unit were calculated using a Gordon Growth methodology with a long-term growth rate of 3%.

During the second quarter of 2008, we performed our annual goodwill impairment test and concluded that the carrying amounts of our goodwill and intangible assets did not exceed fair value. At June 30, 2008, the market price for our shares closed at $49.23 and our market capitalization value was $13.6 billion, based on the weighted average diluted share count of 277.1 million shares at June 30, 2008. Since June 30, 2008, several market factors have combined to cause a significant decrease in our stock price market capitalization. At December 31, 2008, the market price for our shares closed at $11.97 and our market capitalization value was $3.3 billion, based on the weighted average diluted share count of 278.4 million shares for the three months ended December 31, 2008. During the period June 30, 2008 to December 31, 2008, oil prices have decreased from $140.00 per barrel to $44.60 per barrel, while natural gas prices have declined from $13.18 per mcf to $5.63 per mcf. The S&P 500 index has decreased from $1,280 to $903 or 30%, while the oilfield services index (OSX) has declined from $354 to $121 or 65%. We believe that the decline in our stock price was principally driven by circumstances that occurred in the stock market as a whole primarily driven by the deteriorating global economic environment. These factors led us to believe a triggering event had occurred requiring a year end goodwill impairment test.

Our year end impairment test of our goodwill and intangible assets required that for two of our ten reporting units that we perform the second step to measure the goodwill impairment loss. The results indicated a permanent impairment to our Canada Well-servicing and Drilling operating segment and Nabors Blue Sky Ltd., one of our Canadian subsidiaries reported in our Other Operating Segments. As such, we recorded $145.4 million and $4.6 million non-cash impairment charges to reduce the carrying value of these assets to their estimated fair value. Our Canada Well-servicing and Drilling operating segment included assets primarily related to acquisitions of Enserco Energy Services Company, Inc. in 2002 and Command Drilling Corporation in 2001. The non-cash impairment charges were determined necessary due to the duration of the economic downturn in Canada and the lack of certainty regarding eventual recovery in valuing this operation. The main factor that impacted our analysis of Nabors Blue Sky Ltd. is that the current downturn in the drilling market and reduced capital spending on the part of our customers has diminished demand for immediate access to remote drilling site by helicopter use. Additionally, we recorded $4.6 million non-cash impairment to certain intangible assets relating to rights and licenses for a helicopter. As part of our review of our goodwill assumptions, we compared the sum of our reporting units estimated fair value which included the fair value of non-operating assets and liabilities less debt to our market capitalization and assessed the reasonableness of our estimated fair value. A prolonged period of lower oil and natural gas prices and its potential impact on our financial results could result in future impairment charges. For the years ended December 31, 2007 and 2006, our annual impairment test indicated the fair value of our reporting unit s goodwill and intangible assets exceeded carrying amounts.

Oil and Gas Properties. We follow the successful efforts method of accounting for our consolidated subsidiaries oil and gas activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Proved oil and gas properties are reviewed when circumstances suggest the need for such a review and, if required, the proved properties are written down to their estimated fair value. Unproved properties are reviewed to determine if there has been impairment of the carrying value, with any such impairment charged to expense in that period. Because of the low natural gas prices at December 31, 2008, we performed an impairment test on our oil and gas properties of our wholly owned Ramshorn business unit. As a result, we recorded a non-cash pre-tax impairment to our oil and gas properties which totaled $21.5 million. We recorded impairment charges of approximately $21.9 million and $9.9 million during the years ended December 31, 2007 and 2006, respectively, related to our oil and gas properties. Estimated fair value includes the estimated present value of all reasonably expected future production, prices, and costs. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated as successful. Other exploratory costs are expensed as incurred. Our provision for depletion is based on the capitalized costs as determined above and is determined on a property-by-property basis using the units-of-production method, with costs being amortized over proved developed reserves.

Our oil and gas joint ventures, which we account for under the equity method of accounting, utilize the full-cost method of accounting for costs related to oil and natural gas properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or market value of unproved properties. The full-cost ceiling is evaluated at the end of each quarter using then current prices for oil and natural gas, adjusted for the impact of derivatives accounted for as cash flow hedges. Our U.S., international and Canadian joint ventures have recorded non-cash pre-tax full cost ceiling test writedowns of which $228.3 million represents our proportionate share of the writedowns recorded during the three months ended December 31, 2008. There was no impairment recorded by our oil and gas joint ventures for the year ended December 31, 2007.

Income Taxes. Deferred taxes represent a substantial liability for Nabors. For financial reporting purposes, management determines our current tax liability as well as those taxes incurred as a result of current operations yet deferred until future periods. In accordance with the liability method of accounting for income taxes as specified in SFAS No. 109, Accounting for Income Taxes, the provision for income taxes is the sum of income taxes both currently payable and deferred. Currently payable taxes represent the liability related to our income tax return for the current year while the net deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported on our consolidated balance sheets. The tax effects of unrealized gains and losses on investments and derivative financial instruments are recorded through accumulated other comprehensive income (loss) within shareholders equity. The changes in deferred tax assets or liabilities are determined based upon changes in differences between the basis of assets and liabilities for financial reporting purposes and the basis of assets and liabilities for tax purposes as measured by the enacted tax rates that management estimates will be in effect when these differences reverse. Management must make certain assumptions regarding whether tax differences are permanent or temporary and must estimate the timing of their reversal, and whether taxable operating income in future periods will be sufficient to fully recognize any gross deferred tax assets. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In determining the need for valuation allowances, management has considered and made judgments and estimates regarding estimated future taxable income and ongoing prudent and feasible tax planning strategies. These judgments and estimates are made for each tax jurisdiction in which we operate as the calculation of deferred taxes is completed at that level. Further, under U.S. federal tax law, the amount and availability of loss carryforwards (and certain other tax attributes) are subject to a variety of interpretations and restrictive tests applicable to Nabors and our subsidiaries. The utilization of such carryforwards could be limited or effectively lost upon certain changes in ownership. Accordingly, although we believe substantial loss carryforwards are available to us, no assurance can be given concerning the realization of such loss carryforwards, or whether or not such loss carryforwards will be available in the future. These loss carryforwards are also considered in our calculation of taxes for each jurisdiction in which we operate. Additionally, we record reserves for uncertain tax positions which are subject to a significant level of management judgment related to the ultimate resolution of those tax positions. Accordingly, management believes that the estimate related to the provision for income taxes is critical to our results of operations. See Part I, Item 1A. Risk Factors We may have additional tax liabilities. See Note 11 in Part II, Item 8. Financial Statements and Supplementary Data for additional discussion.

Effective January 1, 2007, we adopted the provisions of the FASB issued Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes. In connection with the adoption of FIN 48, we recognized increases to our tax reserves for uncertain tax positions and interest and penalties. See Note 11 in Part II, Item 8. Financial Statements and Supplementary Data for additional discussion.

We are subject to income taxes in both the United States and numerous foreign jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. In the ordinary course of our business, there are many transactions and calculations where the ultimate tax determination is uncertain. We are regularly under audit by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than that which is reflected in historical income tax provisions and accruals. Based on the results of an audit or litigation, a material effect on our financial position, income tax provision, net income, or cash flows in the period or periods for which that determination is made could result. However, certain events could occur that would materially affect management s estimates and assumptions regarding the deferred portion of our income tax provision, including estimates of future tax rates applicable to the reversal of tax differences, the classification of timing differences as temporary or permanent, reserves recorded for uncertain tax positions, and any valuation allowance recorded as a reduction to our deferred tax assets. Management s assumptions related to the preparation of our income tax provision have historically proved to be reasonable in light of the ultimate amount of tax liability due in all taxing jurisdictions.

For the year ended December 31, 2008, our provision for income taxes from continuing operations was $250.4 million, consisting of $188.8 million of current tax expense and $61.6 million of deferred tax expense. Changes in management s estimates and assumptions regarding the tax rate applied to deferred tax assets and liabilities, the ability to realize the value of deferred tax assets, or the timing of the reversal of tax basis differences could potentially impact the provision for income taxes. Changes in these assumptions could potentially change the effective tax rate. A 1% change in the effective tax rate from 31.2% to 32.2% would increase the current year income tax provision by approximately $8 million.

Self-Insurance Reserves. Our operations are subject to many hazards inherent in the drilling, workover and well-servicing industries, including blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment and damage or loss from inclement weather or natural disasters. Any of these hazards could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage and damage to the property of others. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our customers by contract for certain of these risks. To the extent that we are unable to transfer such risks to customers by contract or indemnification agreements, we seek protection through insurance. However, there is no assurance that such insurance or indemnification agreements will adequately protect us against liability from all of the consequences of the hazards described above. Moreover, our insurance coverage generally provides that we assume a portion of the risk in the form of a deductible or self-insured retention.

Based on the risks discussed above, it is necessary for us to estimate the level of our liability related to insurance and record reserves for these amounts in our consolidated financial statements. Reserves related to self-insurance are based on the facts and circumstances specific to the claims and our past experience with similar claims. The actual outcome of self-insured claims could differ significantly from estimated amounts. We maintain actuarially-determined accruals in our consolidated balance sheets to cover self-insurance retentions for workers compensation, employers liability, general liability and automobile liability claims. These accruals are based on certain assumptions developed utilizing historical data to project future losses. Loss estimates in the calculation of these accruals are adjusted based upon actual claim settlements and reported claims. These loss estimates and accruals recorded in our financial statements for claims have historically been reasonable in light of the actual amount of claims paid.

Because the determination of our liability for self-insured claims is subject to significant management judgment and in certain instances is based on actuarially estimated and calculated amounts, and because such liabilities could be material in nature, management believes that accounting estimates related to self-insurance reserves are critical.

For the years ended December 31, 2008, 2007 and 2006, no significant changes have been made to the methodology utilized to estimate insurance reserves. For purposes of earnings sensitivity analysis, if the December 31, 2008 reserves for insurance were adjusted (increased or decreased) by 10%, total costs and other deductions would have changed by $16.3 million, or 0.4%.

Fair Value of Assets Acquired and Liabilities Assumed. We have completed a number of acquisitions in recent years as discussed in Note 5 in Part II, Item 8. Financial Statements and Supplementary Data. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed in the various business combinations, which involved the use of various assumptions. These estimates may be affected by such factors as changing market conditions, technological advances in the industry or changes in regulations governing the industry. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and equipment, and the resulting amount of goodwill, if any. Unforeseen changes in operations or technology could substantially alter management s assumptions and could result in lower estimates of values of acquired assets or of future cash flows. This could result in impairment charges being recorded in our consolidated statements of income. As the determination of the fair value of assets acquired and liabilities assumed is subject to significant management judgment and a change in purchase price allocations could result in a material difference in amounts recorded in our consolidated financial statements, management believes that accounting estimates related to the valuation of assets acquired and liabilities assumed are critical.

The determination of the fair value of assets and liabilities are based on the market for the assets and the settlement value of the liabilities. These estimates are made by management based on our experience with similar assets and liabilities. For the years ended December 31, 2008, 2007 and 2006, no significant changes have been made to the methodology utilized to value assets acquired or liabilities assumed. Our estimates of the fair values of assets acquired and liabilities assumed have proved to be reliable.

Given the nature of the evaluation of the fair value of assets acquired and liabilities assumed and the application to specific assets and liabilities, it is not possible to reasonably quantify the impact of changes in these assumptions.

Share-Based Compensation. We have historically compensated our executives and employees through the awarding of stock options and restricted stock. Based on the requirements of SFAS 123(R), which we adopted on January 1, 2006, we account for stock option and restricted stock awards in 2006, 2007 and 2008 using a fair-value based method, resulting in compensation expense for stock-based awards being recorded in our consolidated statements of income. Determining the fair value of stock-based awards at the grant date requires judgment, including estimating the expected term of stock options, the expected volatility of our stock and expected dividends. In addition, judgment is required in estimating the amount of stock-based awards that are expected to be forfeited. Because the determination of these various assumptions is subject to significant management judgment and different assumptions could result in material differences in amounts recorded in our consolidated financial statements beginning in the first quarter of 2006, management believes that accounting estimates related to the valuation of stock options are critical.

The assumptions used to estimate the fair market value of our stock options are based on historical and expected performance of our common shares in the open market, expectations with regard to the pattern with which our employees will exercise their options and the likelihood that dividends will be paid to holders of our common shares. For the years ended December 31, 2008, 2007 and 2006, no significant changes have been made to the methodology utilized to determine the assumptions used in these calculations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Foreign Currency Risk. We operate in a number of international areas and are involved in transactions denominated in currencies other than U.S. dollars, which exposes us to foreign exchange rate risk. The most significant exposures arise in connection with our operations in Canada, which usually are substantially unhedged.

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, 2008 would result in a $6.2 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 and non-marketable securities, accounts receivable and our range cap and floor derivative instrument. Cash equivalents such as deposits and temporary cash investments are held by major banks or investment firms. Our investments in marketable and non-marketable securities are managed within established guidelines which limit the amounts that may be invested with any one issuer and which provide guidance as to issuer credit quality. Certain of our non-marketable securities are invested in a fund that invests in securities which have been significantly impacted by the current credit market and comprise approximately $4.8 million of our $15.7 million long-term investments in our cash and investment portfolio as of December 31, 2008. We believe that the credit risk in our cash and investment portfolio is minimized as a result of the mix of our investments. 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. However, we do occasionally require prepayment of amounts from customers whose creditworthiness is in question prior to provision of services to those customers. We maintain reserves for potential credit losses, and such losses have been within management s expectations.

Interest Rate, and Marketable and Non-marketable Security Price Risk. Our financial instruments that are potentially sensitive to changes in interest rates include the $2.75 billion 0.94% senior exchangeable notes due 2011, our 4.875%, 5.375% and 6.15% senior notes, our range cap and floor derivative instrument, our investments in debt securities (including corporate, asset-backed, U.S. Government, foreign government, mortgage-backed debt and mortgage-CMO debt securities) and our investments in overseas funds investing primarily in a variety of public and private U.S. and non-U.S. securities (including asset-backed securities and mortgage-backed securities, global structured asset securitizations, whole loan mortgages, and participations in whole loans and whole loan mortgages), which are classified as non-marketable securities.

We may utilize derivative financial instruments that are intended to manage our exposure to interest rate risks. We account for derivative financial instruments under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, and SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, (collectively, SFAS 133, as amended). 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, which has been designated as a fair value hedge under SFAS 133, as amended. Additionally, on October 21, 2002, we purchased a LIBOR range cap and sold a LIBOR floor, in the form of a cashless collar, with the same third-party financial institution with the intention of mitigating and managing our exposure to changes in the three-month U.S. dollar LIBOR rate. This transaction does not qualify for hedge accounting treatment under SFAS 133, as amended, and any change in the cumulative fair value of this transaction is reflected as a gain or loss in our consolidated statements of income. In June 2004, we unwound $100 million of the $200 million range cap and floor derivative instrument. During the fourth quarter of 2005, we unwound the interest rate swap resulting in a loss of $2.7 million, which has been deferred and will be recognized as an increase to interest expense over the remaining life of our 5.375% senior notes due 2012. During the year ended December 31, 2005, we recorded interest savings related to our interest rate swap agreement accounted for as a fair value hedge of $2.7 million, which served to reduce interest expense.

The fair value of our range cap and floor transaction is recorded as a derivative liability, included in other long-term liabilities, totaled approximately $4.7 million as of December 31, 2008 and was nominal as of December 31, 2007. We recorded losses of approximately $4.7 million and $1.3 million for the years ended December 31, 2008 and 2007, respectively, and gains of approximately $1.4 million for the year ended December 31, 2006, related to this derivative instrument; such amounts are included in losses (gains) on sales, retirements and impairments of long-lived assets and other expense (income), net in our consolidated statements of income.

A hypothetical 10% adverse shift in quoted interest rates as of December 31, 2008 would decrease the fair value of our range cap and floor derivative instrument by approximately $.4 million.

In September 2008 we entered into a three-month written put option for 1 million of our common shares with a strike price of $25 per common share. We settled this contract during the fourth quarter of 2008 and paid cash of $22.6 million, net of the premium received, and recognized a loss of $9.9 million which is included in losses (gains) on sales, retirements and impairments of long-lived assets and other expense (income), net in our consolidated statements of income.

Fair Value of Financial Instruments. As of January 1, 2008, we adopted FAS No. 157 and have estimated the fair value of our financial instruments in accordance with this framework. The fair value of our fixed rate long-term debt is estimated based on quoted market prices or prices quoted from third-party financial institutions. The carrying and fair values of our long-term debt, including the current portion, are as follows:

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	December 31,					
	2008			2007		
(In thousands, except interest rates)	Effective Interest Rate	Carrying Value	Fair Value	Effective Interest Rate	Carrying Value	Fair Value
$2.75 billion 0.94% senior exchangeable notes due May 2011	1.16%	$ 2,650,000(1)	$ 2,199,500	1.15%	$ 2,750,000	$ 2,595,313
6.15% senior notes due February 2018	6.42%	963,859	835,244			
$700 million zero coupon senior exchangeable notes due June 2023 (2)				0.32%	700,000	696,990
5.375% senior notes due August 2012	5.69%(3)	272,724(4)	262,411	5.69% (3)	272,097(4)	279,043
4.875% senior notes due August 2009	5.10%	224,829	227,239	5.10%	224,562	225,709
$82.8 million zero coupon convertible senior debentures due February 2021 (5)				2.48% (6)	59,774	56,897
Other	4.50%	1,329	1,329			
		$ 4,112,741	$ 3,525,723		$ 4,006,433	$ 3,853,952

(1) In 2008 we purchased $100 million par value of these notes in the open market, leaving $2.65 billion par value outstanding at December 31, 2008.

(2) In May 2008 Nabors Delaware called for redemption of all of its $700 million zero coupon senior exchangeable notes due 2023 and paid cash of $700.0 million to the noteholders during June and

July 2008. The total amount paid to effect the redemption and related exchange was $700 million in cash and the issuance of approximately 5.25 million of our common shares with a fair value of $249.8 million, the price equal to the principal amount of the notes plus the excess of the exchange value of the notes over their principal amount.

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

(4) Includes $1.5 million and $1.9 million as of December 31, 2008 and 2007, respectively, related to the unamortized loss on the interest rate swap that was unwound during the fourth quarter of 2005.

(5) In June 2008 Nabors

Delaware called for redemption the full $82.8 million aggregate principal amount at maturity of its zero coupon senior convertible debentures due 2021 and in July 2008, paid cash of $60.6 million; equal to the issue price of $50.4 million plus accrued original issue discount of $10.2 million.

(6) Represents the rate at which accretion of the original discount at issuance of these debentures is charged to interest expense.

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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, cash equivalents, short-term and long-term investments and other receivables are included in the table below:

	December 31,					
	2008			2007		
(In thousands, except interest rates)	Fair Value	Interest Rates	Weighted-Average Life (Years)	Fair Value	Interest Rates	Weighted-Average Life (Years)
Cash and cash equivalents	$ 442,087	.51%-2.0%	0.00	$ 531,306	3.15%-6.07%	0.01
Short-term investments:						
Trading equity securities	14,263					
Available-for-sale equity securities	55,453					
Available-for-sale debt securities:						
Commercial paper and CDs	1,119	2.75%	.6			
Corporate debt securities	40,302	1.5%-14.00%	3.5	95,456	4.38%-7.60%	0.5
U.S. Government debt securities	1,816	6.0%	.1	20,048	3.06%-3.32%	1.2
Government agencies debt securities				39,634	4.25%-5.14%	1.1
Mortgage-backed debt securities	7,619	3.98%-5.42%	.9	6,788	2.79%-5.39%	1.5
Mortgage-CMO debt securities	15,326	1.58%-8.73%	.9	23,784	2.49%-5.68%	0.9
Asset-backed debt securities	6,260	.51%-5.19%	6.3	50,035	3.96%-10.53%	1.1
Total available-for-sale debt securities	72,442			235,745		
Total available-for-sale securites	127,895			235,745		
Total short-term investments	142,158			235,745		
Long-term investments and other receivables:						
Actively-managed funds	15,710	N/A		236,253	N/A	
Oil and gas financing receivables	224,242	13.10%-13.52%		123,281	13.10%-13.52%	
Total long-term investments and other receivables	239,952			359,534		
Total cash, cash equivalents, short-term and long-term investments and other receivables	$ 824,197			$ 1,126,585		

Our investments in debt securities listed in the above table and a portion of our long-term investments are sensitive to changes in interest rates. Additionally, our investment portfolio of 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 securities as of December 31, 2008 would decrease the fair value of our trading securities and available-for-sale securities by $1.4 million and $12.8 million, respectively.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, shareholders equity and cash flows present fairly, in all material respects, the financial position of Nabors Industries Ltd. and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we consider necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions in 2007.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

Houston, Texas

February 27, 2009

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CONSOLIDATED BALANCE SHEETS
Nabors Industries Ltd. and Subsidiaries

(In thousands, except per share amounts)	December 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 442,087	$ 531,306
Short-term investments	142,158	235,745
Accounts receivable, net	1,160,768	1,039,238
Inventory	150,118	133,786
Deferred income taxes	28,083	12,757
Other current assets	243,379	252,280
Total current assets	2,166,593	2,205,112
Long-term investments and other receivables	239,952	359,534
Property, plant and equipment, net	7,282,042	6,632,612
Goodwill	175,749	368,432
Investment in unconsolidated affiliates	411,727	404,842
Other long-term assets	191,919	132,850
Total assets	$ 10,467,982	$ 10,103,382
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 225,030	$ 700,000
Trade accounts payable	424,908	348,524
Accrued liabilities	367,393	348,515
Income taxes payable	111,528	97,093
Total current liabilities	1,128,859	1,494,132
Long-term debt	3,887,711	3,306,433
Other long-term liabilities	261,878	246,714
Deferred income taxes	497,415	541,982
Total liabilities	5,775,863	5,589,261
Commitments and contingencies (Note 15)		
Shareholders equity:		
Common shares, par value $.001 per share:		
Authorized common shares 800,000; issued 312,343 and 305,458, respectively	312	305
Capital in excess of par value	1,705,907	1,710,036
Accumulated other comprehensive income	53,520	322,635
Retained earnings	3,910,253	3,359,080
Less: treasury shares, at cost, 29,414 and 26,122 common shares, respectively	(977,873)	(877,935)
Total shareholders equity	4,692,119	4,514,121

Total liabilities and shareholders equity	$ 10,467,982	$ 10,103,382

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