NABORS INDUSTRIES LTD
Form 10-K
February 26, 2010

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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, 2009

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 001-32657
NABORS INDUSTRIES LTD.
(Exact name of registrant as specified in its charter)

Bermuda *(State or Other Jurisdiction of Incorporation or Organization)*	**980363970** *(I.R.S. Employer Identification No.)*
Mintflower Place **8 Par-La-Ville Road** **Hamilton, HM08** **Bermuda** *(Address of principal executive offices)*	**N/A** *(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 whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months. 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. þ

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 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 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 228,620,332 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, 2009, of $15.58 per share as reported on the New York Stock Exchange, was $3,561,904,773. 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 24, 2010 was 284,669,913.

DOCUMENTS INCORPORATED BY REFERENCE (to the extent indicated herein)

Specified portions of the 2010 Notice of Annual Meeting of Shareholders and the definitive Proxy Statement to be distributed in connection with the 2010 annual meeting of shareholders (Part III).

NABORS INDUSTRIES LTD.

Form 10-K Annual Report

For the Year Ended December 31, 2009

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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 Securities Exchange Act of 1934 (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, could, may, predict and similar expressions are intended to ident 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 refer to Part I, Item 1A. Risk Factors.

Unless the context requires otherwise, references in this report to we, us, our, the Company, or Nabors means Na 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 542 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 558 rigs for land workover and well-servicing work in the United States, primarily in the southwestern and western United States, and actively market approximately 172 land workover and well-servicing rigs in Canada. Nabors is a leading provider of offshore platform workover and drilling rigs, and actively markets 40 platform, 13 jack-up 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 select domestic and international markets. We provide logistics services for onshore drilling in Canada using helicopters and fixed-wing 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 joint ventures 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.

Special-purpose drilling rigs used to perform workover services consist of a mobile carrier, which includes an engine, drawworks and a mast, together with other standard drilling accessories and specialized equipment for servicing wells. These rigs are specially designed for major repairs and modifications of oil and gas wells, including standard drilling functions. A well-servicing rig is specially designed for periodic maintenance of oil and gas wells for which service is required to maximize the productive life of the wells. The primary function of a 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, although they also can perform standard drilling functions. Because of size and cost considerations, these specially designed rigs are used for these operations rather than the larger drilling rigs typically used for the initial drilling job.

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; 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 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 its legs and by 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. We also own 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 21 Segment Information 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 more than 10% of our consolidated revenues in 2009 or 2008.

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. Most of our recent contracts for newly constructed rigs have three-year terms. 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. Contract terms and rates 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 our 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.

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. They also occasionally include drilling services. 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. 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 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. Workovers normally are carried out with a rig that includes standard drilling accessories such as rotary drilling equipment, mud pumps, mud tanks and blowout preventers plus other specialized equipment for servicing rigs. A workover may last anywhere from a few days to several weeks. We are paid a daily 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; the supply, removal and disposal of specialized fluids used during certain completion and workover operations; and the removal and disposal of salt water that often accompanies 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.

Oil and Gas Investments

Through our wholly owned Ramshorn business unit, we invest in oil and gas exploration, development and production operations in the United States, Canada and internationally. In addition, in 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 a 50% ownership interest in the Canadian entity and 49.7% ownership interests in the U.S. and international entities. We account for these investments using the equity method of accounting. Each joint venture pursues development and exploration projects with both existing Nabors customers and other operators in a variety of forms, including operated and non-operated working interests, joint ventures, farm-outs and acquisitions. Our Ramshorn business unit through both wholly owned and joint venture operations is focused on the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids in Alaska, Arkansas, Louisiana, Oklahoma, Mississippi, Montana, North Dakota, Texas, Utah and Wyoming. Outside of the United States, we and our joint ventures own or have interests in the Canadian provinces of Alberta and British Columbia and 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. We market our top drives throughout the world. During the last three years, approximately 41% of our top drive sales were made to other Nabors companies. We also rent top drives and catwalks, and provide installation, repair and maintenance services to our customers. We also offer rig instrumentation equipment, including proprietary RIGWATCH™ software and computerized equipment that monitors a rig s real-time performance. Our directional drilling system, ROCKIT™, is experiencing high growth in the marketplace. In addition, we specialize in daily reporting software for drilling operations, making this data available through the internet. We also provide mudlogging services. Canrig Drilling Technology Canada Ltd., one of our Canadian subsidiaries, manufactures catwalks which are installed on both onshore and offshore drilling rigs. During the last three years, approximately 63% of our 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 equipment and provides data collection services to oil and gas exploration and service companies. Nabors has a 50% ownership 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 general contractor involved in the construction of roads, bridges, dams, drill sites and other facility sites, as well as the provision of mining support in Alaska; the other member of Alaska Interstate Construction, L.L.C. is a subsidiary of Cook Inlet Region, Inc. Revenues are derived from services to companies engaged in mining and public works. Nabors Blue Sky Ltd. leases aircraft used for logistics services for onshore drilling in Canada using helicopters and fixed-wing aircraft.

Our Employees

As of December 31, 2009, Nabors employed approximately 18,390 persons, of whom approximately 3,148 were employed by unconsolidated affiliates. We believe our relationship with our employees is generally good.

Some 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 quarter of each year. Global warming could lengthen these periods of reduced activity, but we cannot currently estimate to what degree. Seasonality does not materially impact 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 maintaining our competitive position within the drilling industry. We expect to continue developing technology internally and acquiring technology through strategic acquisitions.

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 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 available rigs has exceeded demand in many of our markets. The land drilling, workover and well-servicing market is generally more competitive than the offshore market due to the larger number of rigs and market participants. From 2005 through most of 2008, demand was strong for drilling services driven by a sustained increase in the level of commodity prices; supply of and demand for land drilling services were in balance in the United States and international markets, with demand actually exceeding supply in some of our markets. This resulted in an increase in rates being charged for rigs across our North American, Offshore and International markets. In late 2008, falling oil prices and the declines in natural gas prices forced a curtailment of drilling-related expenditures by many companies and resulted in an oversupply of rigs in the markets where we operate. During 2009, this continued decline in drilling and related activity impacted our key markets. Although many 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 increases based on the price and supply of existing and new rigs across all of our markets.

In all of our geographic markets, we believe price and the 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 the ability to offer ancillary services. Increasingly, the ability to deliver rigs with new technology and features is becoming a competitive factor. In international markets, experience in operating in certain environments, as well as customer alliances 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 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, we compete with many firms of varying size, several of which have more significant operations in those areas than Nabors. Internationally, we compete directly with various contractors at each location where we operate. We believe 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 Drilling Technology Ltd. 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 in each of our 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 Granite Construction Company, NANA 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, we have adhered to a consistent strategy aimed at positioning Nabors to grow and prosper in times of good market conditions 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.

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 expanding 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 recent years illustrate our implementation of this strategy and its continuing success. Beginning in 2005, 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 and least capable rigs in our existing fleet. However, this positive trend in the rig market slowed in the fourth quarter of 2008 and throughout much of 2009, 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 were reduced and the demand for additional rigs was substantially reduced. Although we expect market conditions to remain challenging during 2010, we believe the deployment of our newer and higher margin rigs under long-term contracts will enhance our competitive position when market conditions improve.

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 542 land drilling rigs, approximately 558 rigs for land workover and well-servicing work in the United States and 172 rigs for land workover and well-servicing work in Canada, 40 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). On this date, Nabors Blue Sky Ltd. (formerly 1183011 Alberta Ltd.) owned 42 helicopters and fixed-wing aircraft and owned and operated a fleet of heliportable well-service equipment. The purchase price was 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 2008 and 2009, the results of our impairment tests of goodwill and intangible assets indicated a permanent impairment to goodwill and to an intangible asset of Nabors Blue Sky Ltd. As such, the goodwill has been fully impaired as of December 31, 2009. 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 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 (loss).

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 currently anticipate that compliance with currently applicable environmental regulations and controls will significantly change its competitive position, capital spending or earnings during 2010. 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 report, 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 continue to adversely affect our results of operations

The recent and substantial volatility and extended declines in oil and natural gas prices in response to a weakened global economic environment has adversely affected our results of operations. In addition, economic conditions have resulted in substantial uncertainty in the capital markets and both access to and terms of available financing. 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 continue to impact our industry and our business, including our future operating results and the ability to recover our assets, including goodwill, at their stated values. In addition, some of our customers could experience an inability to pay suppliers, including us, 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 depend on the level of spending by oil and gas companies for exploration, development and production activities. Both short-term and long-term trends in oil and natural gas prices affect these levels. Oil and natural gas prices, as well as the level of drilling, exploration and production activity, can be highly volatile. Worldwide military, political and economic events, including initiatives by the Organization of Petroleum Exporting Countries, 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. Recent volatility and the effects of recent declines in oil and natural gas prices are 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 could continue to depress the level of exploration and production activity. Lower oil and natural gas prices have also caused some of our customers to seek to terminate, renegotiate or fail to honor our drilling contracts and affected the fair market value of our rig fleet, which in turn has resulted in impairments of our assets. A prolonged period of lower oil and natural gas prices could affect our ability to retain skilled rig personnel and affect our ability to access 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 have a substantial amount of debt outstanding

As of December 31, 2009, we had long-term debt outstanding of approximately $3.9 billion, including $.2 million in current maturities and $1.6 billion in long-term debt that matures in May 2011, and cash and cash equivalents and investments of $1.2 billion, including $100.9 million of long-term investments and other receivables. Long-term investments and other receivables include $92.5 million in oil and gas financing receivables. Our ability to service our debt obligations depends in large part upon the level of cash flows generated by our subsidiaries operations and our access to capital markets. If our 0.94% senior exchangeable notes were exchanged before their maturity in May 2011, 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 calculate our leverage in relation to our capital (i.e., shareholders equity) utilizing two commonly used ratios:

Gross funded debt to capital ratio, which is calculated by dividing (x) funded debt by (y) funded debt *plus* deferred tax liabilities (net of deferred tax assets) *plus* capital. Funded debt is the sum of (1) short-term borrowings, (2) the current portions of long-term debt and (3) long-term debt; and

Net funded debt to capital ratio, which is calculated by dividing (x) net funded debt by (y) net funded debt *plus* deferred tax liabilities (net of deferred tax assets) *plus* capital. Net funded debt is funded debt *minus* the sum of cash and cash equivalents and short-term and long-term investments and other receivables.

At December 31, 2009, our gross funded debt to capital ratio was 0.41:1 and our net funded debt to capital ratio was 0.33:1.

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 that we have made to our operating subsidiaries and income from dividends and other cash flow from our subsidiaries. There can be no assurance that our operating subsidiaries will generate sufficient net income to pay us dividends or sufficient cash flow to make payments of interest and principal to us. In addition, from time to time, our operating subsidiaries may enter into financing arrangements that contractually restrict or prohibit these types of upstream payments to us. There can also be adverse tax consequences associated with paying dividends.

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 Fitch Ratings, Moody s Investor Service and Standard & Poor s, which are currently BBB+, Baa1 and BBB+ , respectively, and our historical ability to access those markets as needed. Standard & Poor s recently affirmed its BBB+ credit rating on Nabors, but revised its outlook to negative from stable in early 2009 due primarily to worsening industry conditions. A credit downgrade may impact our future ability to access credit markets, which is important for purposes of both meeting our financial obligations and funding capital requirements to finance and grow our businesses.

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

The oilfield services industry 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 some of these risks. To the extent that we are unable to transfer these risks to customers by contract or indemnification agreements, we seek protection through insurance. However, there is no assurance that our 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. Even if available, insurance may be inadequate or insurance premiums or other costs may rise significantly in the future making insurance prohibitively expensive. We expect to continue to face upward pressure in our insurance renewals; our premiums and deductibles may be higher, and some insurance coverage may either 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 our overall costs.

Future price declines may result in a writedown of our oil and gas 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. Proved property acquisition costs are amortized over total proved reserves. Costs of wells and related equipment and facilities are amortized over the life of proved developed reserves. Proved oil and gas properties are reviewed when circumstances suggest the need for such a review and are written down to their estimated fair value, if required. Unproved properties are reviewed periodically to determine if there has been impairment of the carrying value; any impairment is expensed 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. During 2009, 2008 and 2007, our impairment tests on the oil and gas-related assets of our wholly owned Ramshorn business unit resulted in impairment charges of $205.9 million, $21.5 million and $41.0 million, respectively. Any sustained further decline in oil and natural gas prices or reserve quantities could require further writedown 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 unconsolidated 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 of these 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 the costs to the aggregate of (i) the present value of future net revenues attributable to proved oil and natural gas reserves, discounted at 10%, plus (ii) the lower of cost or market value of unproved properties. The full-cost ceiling was evaluated at December 31, 2009 using the 12-month average price, whereas during 2008 and 2007, the full-cost ceiling was evaluated using year-end prices. During 2009 and 2008, our unconsolidated oil and gas joint ventures recorded full-cost ceiling test writedowns, of which $237.1 million and $228.3 million, respectively, represented our proportionate share. During 2007, our joint ventures did not record full-cost ceiling test writedowns. Any sustained further decline in oil and natural gas prices, or other factors, without other mitigating circumstances, could cause other future writedowns of capitalized costs and asset impairments that could adversely affect our results of operations.

The profitability of our operations outside the United States 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, such as the recent foreign currency devaluation in Venezuela. In the international markets where 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.

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, with terms through March 30, 2013. If either Mr. Isenberg s or Mr. Petrello s employment is terminated in the event of death or disability, or without cause or in the event of a change in control, significant cash payments up to $100 million and $50 million, respectively, would be made by the Company. We do not carry significant amounts of key man insurance. The loss of Mr. Isenberg or Mr. Petrello could have an adverse effect on our financial condition or results of operations.

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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 and local laws, rules and regulations. Our cost of compliance with these laws, rules and regulations may be substantial. For example, federal law imposes on responsible parties a variety of regulations 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, 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. Various state and federal laws govern 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 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.

The scope of laws protecting the environment has expanded, particularly outside the U.S., and this trend is expected to continue. The 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. Violations may also result in liabilities for personal injuries, property damage and other costs and claims. We generally require customers to assume responsibility for environmental liabilities. However, we are not always successful in allocating all of these risks to customers, and there is no assurance that customers who assume the risks will be financially able to bear them.

Under the Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or Superfund, and similar state laws and regulations, liability for release of a hazardous substance into the environment 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 of any party that contributed to the release. Liability under CERCLA may include costs of cleaning up the hazardous substances that have been released into the environment and damages to natural resources.

Changes in U.S. 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 the U.S. Congress that would reclassify some 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, regulators in the United States and other jurisdictions in which we operate are increasingly focused on restricting the emission of carbon dioxide, methane and other greenhouse gases that may contribute 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 of which 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 U.S. 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.

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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 could adversely affect the market price of our common shares

As of February 24, 2010, we had 800,000,000 authorized common shares, of which 284,669,913 shares were outstanding. In addition, 40,641,861 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. 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 under 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 in 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, the Board of Directors has the authority to issue a significant number 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 any vote or action by the holders of our common shares. Although we have no current plans to issue preferred shares, our classified Board, as well as its ability to issue preferred shares, may discourage, delay or prevent changes in control of Nabors that are not supported by the Board, thereby preventing some of our shareholders from realizing a premium on their shares. In addition, the requirement in the indenture for our 0.94% 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.

We have employment agreements with our Chairman and Chief Executive Officer, Eugene M. Isenberg, and our Deputy Chairman, President and Chief Operating Officer, Anthony G. Petrello. These agreements have change-in-control provisions that could result in significant cash payments to Messrs. Isenberg and Petrello.

We may have additional tax liabilities

We are subject to income taxes in the United States and numerous other 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 what is reflected in income tax provisions and accruals. An audit or litigation could materially affect our financial position, income tax provision, net income, or cash flows in the period or periods challenged. It is also possible that future changes to tax laws (including tax treaties) could impact our ability to realize the tax savings recorded to date.

On September 14, 2006, Nabors Drilling International Limited, one of our wholly owned Bermuda subsidiaries (NDIL), received a Notice of Assessment (the Notice) from Mexico s federal tax authorities in connection with the audit of NDIL s Mexican branch for 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 was approximately $19.8 million (including interest and penalties). Nabors and its tax advisors previously concluded that the deductions were appropriate and more recently that the government s position lacks merit. NDIL s Mexican branch took similar deductions for depreciation and labor expenses from 2004 to 2008. On June 30, 2009, the government proposed similar assessments against the Mexican branch of another wholly owned Bermuda subsidiary, Nabors Drilling International II Ltd. (NDIL II) for 2006. We anticipate that a similar assessment will eventually be proposed against NDIL for 2004 through 2008 and against NDIL II for 2007 to 2009. We believe that the potential assessments will range from $6 million to

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$26 million per year for the period from 2004 to 2009, and in the aggregate, would be approximately $90 million to $95 million. Although we believe that any assessments related to the 2004 to 2009 years would also lack merit, a reserve has been recorded in accordance with accounting principles generally accepted in the United States of America (GAAP). If these additional assessments were to be made and we ultimately did not prevail, we would be required to recognize additional tax for the amount of the aggregate over the current reserve.

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

Various bills have been introduced in Congress that 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 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 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 impact 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 subject to legal proceedings and governmental investigations from time to time that include employment, tort, intellectual property and other claims, and purported class action and shareholder derivative actions. We are also subject to complaints and 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 that could have an adverse effect on our financial condition or results of operations.

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, some 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 a particular fund or investment managers. As a result, events or developments that negatively affect the value of our investments could have an adverse effect on our results of operations.

We do not currently intend to pay dividends

We have not paid any cash dividends on our common shares since 1982 and have no current intention to do so. However, we can give no assurance that we will not reevaluate our position on dividends in the future.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

Not applicable.

ITEM 2. *PROPERTIES*

Many of the international drilling rigs and some 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, including various helicopters, fixed-wing aircraft and heliportable well-service equipment, which are used to support drilling and logistics operations.

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Nabors and its subsidiaries own or lease executive and administrative office space in Hamilton, Bermuda (principal executive office); Anchorage, Alaska; Romance, Arkansas; New Iberia and Youngsville, Louisiana; Bakersfield, Coalinga, Rancho Dominguez-Compton and Ventura, California; Duson, Houma, Lafayette, Minden, New Iberia, Shreveport and Youngsville, Louisiana; Laurel, Mississippi; Alice, Andrews, Big Lake, Big Spring, Breckenridge, Bridgeport, Bryan, Corpus Christi, Crane, Cresson, Crosby, Decator, Denver City, El Campo, Fairfield, Fort Stockton, Haslet, Hillsboro, Houston, Iraan, Kilgore, La Grange, Longview, Magnolia, Midland, Mission, Monohans, Nacogdoches, Odessa, Ozona, Palestine, San Angelo, Snyder, Sonora, Three Rivers and Victoria, Texas; Roosevelt, Utah; Casper, Wyoming; El Reno, Enid, Hartshorne, Lindsay, Oklahoma City, Pocola and Weatherford, Oklahoma; Baker, Billings and Plentywood, Montana; Belfield and Williston, North Dakota; Carlsbad, Eunice and Hobbs, New Mexico; Denver, Fort Lupton, Fruita and Grand Junction, Colorado; Casper and Rock Springs, Wyoming; Mendoza, Argentina; Victoria, Australia; Santa Cruz, Bolivia; Alberta, Brooks, Clairmont, Drayton Valley, Leduc, Lloydminster, Nisku, Slave Lake and Whitecourt, Canada; Bogota, Colombia; Quito, Ecuador; Mumbai, India; Dubai, U.A.E.; Dhahran, Saudi Arabia; Hassi-Messaoud, Algeria; Atyrau and East Ahmadi, Kazakhstan; Ahmadi, Kuwait; Tripoli, Libya; CD Del Carmen, Mexico; Azaira and Muscat, Oman; Guanghan, Peoples Republic of China; Doha, Qatar; Luanda, Republic of Angola; Port Gentil, Republic of Gabon; Kuala Lumpur, Malaysia; Pointe Noire, Congo; Moscow, Russia; Ploeisti, Romania; Maracaibo, Venezuela; Perth, Western Australia; and Sana a, Yemen. 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.

Additional information about our properties can be found in Notes 2 Summary of Significant Accounting Policies and 8 Property, Plant and Equipment (each, under the caption Property, Plant and Equipment) and 15 Commitments and Contingencies (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 years ended December 31, 2009, 2008 and 2007, can be found in Note 21 Segment Information. A description of our rig fleet is included under the caption Introduction in Part I, Item 1. Business.

Management believes that our existing equipment and facilities 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 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 one of our vendors and compliance with the Foreign Corrupt Practices Act. The inquiry relates to transactions with and involving Panalpina, which provides freight-forwarding and customs-clearance services to some 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 engaged outside counsel to review some of our transactions with this vendor. The Audit Committee 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

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obtaining permits for the temporary importation of equipment and clearance of goods and materials through customs. Both the SEC and the Department of Justice have been advised of the Company s investigation. The ultimate outcome of this investigation or the effect of implementing any further measures that may be necessary to ensure full compliance with applicable laws cannot be determined at this time.

A court in Algeria entered a judgment of approximately $19.7 million against us related to alleged customs infractions in 2009. We believe we did not receive proper notice of the judicial proceedings, and that the amount of the judgment is excessive. We have asserted the lack of legally required notice as a basis for challenging the judgment on appeal to the Algeria Supreme Court. 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 and the timing thereof are 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 $19.7 million.

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

Not applicable.

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, 2004 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, 2005 2009.

	2005	2006	2007	2008	2009
Nabors Industries Ltd.	**148**	**116**	**107**	**47**	**85**
S&P 500 Index	105	121	128	81	102
Dow Jones Oil Equipment and Services Index	152	172	250	102	168

I. Market and Share Prices

Our common shares are traded on the New York Stock Exchange under the symbol NBR . At February 24, 2010, there were approximately 1,774 shareholders of record. We have not paid any cash dividends on our common shares since 1982 and currently have no intentions to do so. However, we can give no assurance that we will not reevaluate our position on dividends in the future.

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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.

Calendar Year	Share Price High	Share Price Low
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
2009		
First quarter	14.05	8.25
Second quarter	19.79	9.38
Third quarter	21.48	13.78
Fourth quarter	24.07	19.18

The following table provides information relating to Nabors repurchase of common shares during the three months ended December 31, 2009:

Period	Total Number of Shares Purchased	Average Price Paid per Share(1)	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Program(2)
October 1 October 31	(1)	$ 20.90		$ 35,458
November 1 November 30	531(1)	$ 22.88		$ 35,458
December 1 December 31	1(1)	$ 21.85		$ 35,458

(1) Shares were withheld from employees to satisfy certain tax withholding obligations due in connection with grants of stock under our 2003 Employee Stock Plan and option exercises from our 1996 Employee Stock Plan. Both the 2003 Employee Stock Plan and 1996 Employee Stock Plan provide for the withholding of shares to satisfy tax obligations, but do not specify a maximum number of shares that can be withheld for this purpose. These shares were not purchased as part of a publicly announced program to purchase common shares.

(2) 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. Through December 31, 2009, $464.5 million of our common shares had been repurchased under this program. As of

December 31, 2009, 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 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.*

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III. Shareholder Matters

Bermuda has exchange controls which apply to residents in respect of the Bermudian dollar. As an exempt company, Nabors is considered to be nonresident for such controls; consequently, there are no Bermuda governmental restrictions on our 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*

erating Data(1)(2)(3) thousands, except per share amounts and ratio data)	Year Ended December 31, 2009	2008	2007	2006	2005
enues and other income:					
erating revenues	$ 3,692,356	$ 5,511,896	$ 4,938,848	$ 4,707,289	$ 3,394,4
nings (losses) from unconsolidated affiliates	(214,681)	(229,834)	17,724	20,545	5,6
estment income (loss)	25,756	21,726	(15,891)	102,007	85,4
al revenues and other income	3,503,431	5,303,788	4,940,681	4,829,841	3,485,5
ts and other deductions:					
ect costs	2,012,352	3,110,316	2,764,559	2,511,392	1,958,5
eral and administrative expenses	429,663	479,984	436,282	416,610	247,1
reciation and amortization	668,415	614,367	469,669	365,357	285,0
letion	11,078	25,442	31,165	38,580	46,8
rest expense	264,948	196,718	154,920	120,507	44,8
ses (gains) on sales and retirements of long-lived assets other expense (income), net	12,962	15,027	11,315	22,204	44,2
airments and other charges	339,129	176,123	41,017		
al costs and other deductions	3,738,547	4,617,977	3,908,927	3,474,650	2,626,6
ome (loss) from continuing operations before income taxes	(235,116)	685,811	1,031,754	1,355,191	858,8
ome tax expense (benefit)	(149,228)	206,147	201,496	407,282	219,0
ome (loss) from continuing operations, net of tax	(85,888)	479,664	830,258	947,909	639,8
ome from discontinued operations, net of tax			35,024	27,727	10,5
income (loss)	(85,888)	479,664	865,282	975,636	650,4
s: Net (income) loss attributable to noncontrolling interest	342	(3,927)	420	(1,914)	(1,7
income (loss) attributable to Nabors	$ (85,546)	$ 475,737	$ 865,702	$ 973,722	$ 648,6
nings (losses) per Nabors share:					
ic from continuing operations	$ (.30)	$ 1.69	$ 2.96	$ 3.25	$ 2.
ic from discontinued operations			.12	.10	.
al Basic	$ (.30)	$ 1.69	$ 3.08	$ 3.35	$ 2.
uted from continuing operations	$ (.30)	$ 1.65	$ 2.88	$ 3.15	$ 1.
uted from discontinued operations			.12	.09	.
al Diluted	$ (.30)	$ 1.65	$ 3.00	$ 3.24	$ 2.
ghted-average number of common shares outstanding:					

ic	283,326	281,622	281,238	291,267	312,6
ıted	283,326	288,236	288,226	300,677	323,7
ital expenditures and acquisitions of businesses(4)	$ 990,287	$ 1,578,241	$ 1,945,932	$ 2,006,286	$ 1,003,2
rest coverage ratio(5)	6.2:1	20.7:1	32.5:1	38.1:1	25.6

Balance Sheet Data(2)(3) (In thousands, except ratio data)	As of December 31, 2009	2008	2007	2006	2005
Cash, cash equivalents, short-term and long-term investments and other receivables(6)	$ 1,191,733	$ 826,063	$ 1,179,639	$ 1,653,285	$ 1,646,327
Working capital	1,568,042	1,037,734	719,674	1,650,496	1,264,852
Property, plant and equipment, net	7,646,050	7,331,959	6,669,013	5,423,729	3,886,924
Total assets	10,644,690	10,517,899	10,139,783	9,155,931	7,230,407
Long-term debt	3,940,605	3,600,533	2,894,659	3,457,675	1,251,751
Shareholders equity	5,167,656	4,904,106	4,801,579	3,889,100	3,758,140
Funded debt to capital ratio:					
Gross(7)	0.41:1	0.41:1	0.39:1	0.43:1	0.32:1
Net(8)	0.33:1	0.35:1	0.30:1	0.28:1	0.08:1

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

(2) The operating data for the year ended December 31, 2005 and the balance sheet data at December 31, 2005 do not reflect the adoption of the revised provisions relating to convertible debt within the Debt with Conversions and Other Options Topic of the Accounting Standards Codification.

(3) 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).

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

(5) The interest coverage ratio is a trailing 12-month quotient of the sum of net income (loss) attributable to Nabors, interest expense, depreciation and amortization, depletion expense, impairments and other charges, income tax expense (benefit) and our proportionate share of full-cost ceiling test writedowns from our unconsolidated oil and gas joint ventures *less* investment income (loss) divided by cash interest expense. This ratio is a method for calculating the amount of operating cash flows available to cover interest expense. The interest coverage 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.

(6) 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. Additionally, the December 31, 2009, 2008 and 2007 amounts include $92.5 million, $224.2 million and $123.3 million, respectively, in oil and gas financing receivables that are included in long-term investments and other receivables.

(7) The gross funded debt to capital ratio is calculated by dividing (x) funded debt by (y) funded debt *plus* deferred tax liabilities (net of deferred tax assets) *plus* capital. Funded debt is the sum of (1) short-term borrowings, (2) the 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.

(8) The net funded debt to capital ratio is calculated by dividing (x) net funded debt by (y) net funded debt *plus* deferred tax liabilities (net of deferred tax assets) *plus* capital. Net funded debt is funded debt *minus* the sum of cash and cash equivalents and short-term and long-term investments and other receivables. 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 thereto.

Nabors is the largest land drilling contractor in the world, with approximately 542 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 558 rigs for land workover and well-servicing work in the United States, primarily in the southwestern and western United States, and approximately 172 rigs for land workover and well-servicing work in Canada. Nabors is a leading provider of offshore platform workover and drilling rigs, and actively markets 40 platform, 13 jack-up 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 select domestic and international markets. We provide logistics services for onshore drilling in Canada using helicopters and fixed-wing 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 in the U.S., Canada and international areas through both our wholly owned subsidiaries and our separate joint venture entities. We hold a 50% ownership interest in our Canadian entity and 49.7% ownership interests in our U.S. and International entities. Each joint venture pursues development and exploration projects with our existing customers and with other operators in a variety of forms, including operated and non-operated working interests, joint ventures, farm-outs and acquisitions.

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 our Oil and Gas operating segment. 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 our Other Operating Segments.

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 their cash flow and earnings which are largely driven 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)			
	2009	2008	2007	2009 to 2008		2008 to 2007	
Commodity prices:							
Average Henry Hub natural gas spot price ($/million cubic feet (mcf))	$ 3.94	$ 8.89	$ 6.97	$ (4.95)	(56)%	$ 1.92	28%
Average West Texas intermediate crude oil spot price ($/barrel)	$ 61.99	$ 99.92	$ 72.23	$ (37.93)	(38)%	$ 27.69	38%

Beginning in the fourth quarter of 2008, there was a significant reduction in the demand for natural gas and oil that was caused, at least in part, by the significant deterioration of the global economic environment including the extreme volatility in the capital and credit markets. Weaker demand throughout 2009 has resulted in sustained lower natural gas and oil prices. The price of natural gas reached a low for 2009 of $1.83 per mcf during September and while showing improvement remains depressed, having averaged $3.77 per mcf during the second half of 2009. The significant drop in the price of oil reached a low for 2009 of $33.98 per barrel in February with continuous recovery throughout 2009, averaging $72.08 per barrel during the second half of 2009. These reduced prices for natural gas and oil have led to a sharp decline in the demand for drilling and workover services. Continued fluctuations in the demand for gas and oil, among other factors including supply, could contribute to continued price volatility which may continue to affect demand for our services and could materially affect our future financial results.

Operating revenues and Earnings (losses) from unconsolidated affiliates for the year ended December 31, 2009 totaled $3.5 billion, representing a decrease of $1.8 billion, or 34% as compared to the year ended December 31, 2008. Adjusted income derived from operating activities and net income (loss) attributable to Nabors for the year ended December 31, 2009 totaled $356.2 million and $(85.5) million ($(.30) per diluted share), respectively, representing decreases of 66% and 118%, respectively, compared to the year ended December 31, 2008. Operating revenues and Earnings (losses) 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 (loss) attributable to Nabors for the year ended December 31, 2008 totaled $1.1 billion and $475.7 million ($1.65 per diluted share), respectively, representing decreases of 16% and 45%, respectively, compared to the year ended December 31, 2007.

During 2009 and 2008, our operating results were negatively impacted as a result of charges arising from oil and gas full-cost ceiling test writedowns and other impairments. Earnings (losses) from unconsolidated affiliates includes $(237.1) million and $(228.3) million, respectively, for the years ended December 31, 2009 and 2008, representing our proportionate share of full-cost ceiling test writedowns from our unconsolidated oil and gas joint ventures which utilize the full-cost method of accounting. During 2009, our joint ventures used a 12-month average price in the ceiling test calculation as required by the revised SEC rules whereas during 2008, the ceiling test calculation used the single-day, year-end commodity price that, at December 31, 2008, was near its low point for that year. The full-cost ceiling test writedowns are included in our Oil and Gas operating segment results.

During 2009 and 2008, our operating results were also negatively impacted as a result of our impairments and other charges of $339.1 million and $176.1 million, respectively. During 2009, impairments and other charges included recognition of other-than-temporary impairments of $54.3 million relating to our available-for-sale securities, and impairments of $64.2 million to long-lived assets that were retired from our U.S. Offshore, Alaska, Canada and International contract drilling segments. Additionally, we recorded impairment charges of $205.9 million and

$21.5 million, respectively, to our wholly owned Ramshorn business unit under application of the successful-efforts method of accounting for some of our oil and gas-related assets during the years ended December 31, 2009 and 2008. During 2008, impairments and other charges included goodwill and intangible asset impairments totaling $154.6 million recorded by our Canada Well-servicing and Drilling operating segment and Nabors Blue Sky Ltd., one of our Canadian subsidiaries reported in Other

Operating Segments. We recognized these goodwill and intangible asset impairments to reduce the carrying value of these assets to their estimated fair value. We consider these writedowns necessary because of the duration of the industry downturn in Canada and the lack of certainty regarding eventual recovery. These impairments and other charges are reflected separately as impairments and other charges in our consolidated statements of income (loss) for the years ended December 31, 2009 and 2008.

Excluding these charges, our operating results were lower than the previous year results primarily due to the continuing weak environment in our U.S. Lower 48 Land Drilling, U.S. Land Well-servicing, Canada and U.S. Offshore operations where activity levels and demand for our drilling rigs have decreased substantially in response to uncertainty in the financial markets and commodity price deterioration. Operating results have been further negatively impacted by higher levels of depreciation expense due to our increased capital expenditures in recent years.

Our operating results for 2010 are expected to approximate levels realized during 2009 given our current expectation of the continuation of lower commodity prices during 2010 and the related impact on drilling and well-servicing activity and dayrates. We expect the decrease in drilling activity and dayrates to continue to adversely impact our U.S. Lower 48 Land Drilling and our U.S. Land Well-servicing operations for 2010, as compared to 2009, because the number of working rigs and average dayrates have declined. We expect our International operations to decrease slightly during 2010 as a result of lower drilling activity and utilization partially offset by the deployment of new and incremental rigs under long-term contracts and the renewal of multi-year contracts. Although rig count is expected to be lower overall, the reductions are primarily comprised of lower yielding assets, leaving higher margin contracts in place partially offset by certain contracts rolling over at lower current market rates. Our investments in new and upgraded rigs over the past five years have resulted in long-term contracts which we expect will enhance our competitive position when market conditions improve.

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

	Year Ended December 31,			Increase/(Decrease)		
	2009	2008	2007	2009 to 2008		2008 to 2
ds, except percentages and rig activity)						
segments:						
evenues and Earnings (losses) from ted affiliates from continuing 1)						
illing:(2)						
48 Land Drilling	$ 1,082,531	$ 1,878,441	$ 1,710,990	$ (795,910)	(42)%	$ 167,451
Vell-servicing	412,243	758,510	715,414	(346,267)	(46)%	43,096
re	157,305	252,529	212,160	(95,224)	(38)%	40,369
	204,407	184,243	152,490	20,164	11%	31,753
	298,653	502,695	545,035	(204,042)	(41)%	(42,340)
1	1,265,097	1,372,168	1,094,802	(107,071)	(8)%	277,366
ntract Drilling(3)	3,420,236	4,948,586	4,430,891	(1,528,350)	(31)%	517,695
(4)(5)	(209,091)	(151,465)	152,320	(57,626)	(38)%	(303,785)
ting Segments(6)(7)	446,282	683,186	588,483	(236,904)	(35)%	94,703
ciling items(8)	(179,752)	(198,245)	(215,122)	18,493	9%	16,877

$	3,477,675	$	5,282,062	$	4,956,572	$	(1,804,387)	(34)%	$	325,490

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	Year Ended December 31,			Increase/(Decrease)		
	2009	2008	2007	2009 to 2008		2008 to 20
nds, except percentages and rig activity)						
come (loss) derived from operating						
om continuing operations:(1)(9)						
illing:						
48 Land Drilling	$ 294,679	$ 628,579	$ 596,302	$ (333,900)	(53)%	$ 32,277
Vell-servicing	28,950	148,626	156,243	(119,676)	(81)%	(7,617)
re	30,508	59,179	51,508	(28,671)	(48)%	7,671
	62,742	52,603	37,394	10,139	19%	15,209
	(7,019)	61,040	87,046	(68,059)	(111)%	(26,006)
l	365,566	407,675	332,283	(42,109)	(10)%	75,392
ntract Drilling(3)	775,426	1,357,702	1,260,776	(582,276)	(43)%	96,926
(4)(5)	(256,535)	(206,490)	97,150	(50,045)	(24)%	(303,640)
ating Segments(7)(8)	34,120	68,572	35,273	(34,452)	(50)%	33,299
ciling items(10)	(196,844)	(167,831)	(138,302)	(29,013)	(17)%	(29,529)
	$ 356,167	$ 1,051,953	$ 1,254,897	$ (695,786)	(66)%	$ (202,944)
ense	(264,948)	(196,718)	(154,920)	(68,230)	(35)%	(41,798)
income (loss)	25,756	21,726	(15,891)	4,030	19%	37,617
s) on sales and retirements of long-lived						
ther income (expense), net	(12,962)	(15,027)	(11,315)	2,065	14%	(3,712)
s and other charges(11)	(339,129)	(176,123)	(41,017)	(163,006)	(93)%	(135,106)
s) from continuing operations before						
s	(235,116)	685,811	1,031,754	(920,927)	(134)%	(345,943)
expense (benefit)	(149,228)	206,147	201,496	(355,375)	(172)%	(4,651)
s) from continuing operations, net of tax	(85,888)	479,664	830,258	(565,552)	(118)%	(350,594)
n discontinued operations, net of tax			35,024			(35,024)
(loss)	(85,888)	479,664	865,282	(565,552)	(118)%	(385,618)
ncome) loss attributable to noncontrolling						
	342	(3,927)	420	4,269	109%	(4,347)
(loss) attributable to Nabors	$ (85,546)	$ 475,737	$ 865,702	$ (561,283)	(118)%	$ (389,965)

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	Year Ended December 31,			Increase/(Decrease)		
	2009	2008	2007	2009 to 2008		2008 to 2007
ousands, except percentages and rig activity)						
tivity:						
ars:(12)						
ower 48 Land Drilling	149.4	247.9	229.4	(98.5)	(40)%	18.5
ffshore	11.0	17.6	15.8	(6.6)	(38)%	1.8
	10.0	10.9	8.7	(0.9)	(8)%	2.2
a	19.7	35.5	36.7	(15.8)	(45)%	(1.2)
tional(13)	100.2	120.5	115.2	(20.3)	(17)%	5.3
ig years	290.3	432.4	405.8	(142.1)	(33)%	26.6
urs:(14)						
and Well-servicing	590,878	1,090,511	1,119,497	(499,633)	(46)%	(28,986)
a Well-servicing	143,824	248,032	283,471	(104,208)	(42)%	(35,439)
ig hours	734,702	1,338,543	1,402,968	(603,841)	(45)%	(64,425)

(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 using the equity method, of $9.7 million, $5.8 million and $5.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(4) Represents our oil and gas exploration, development and production operations. Includes our proportionate share of full-cost ceiling test writedowns recorded by our unconsolidated oil and gas joint ventures of $(237.1) million and $(228.3) million for the years ended December 31, 2009 and 2008, respectively.

(5) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $(241.9) million, $(241.4) million and $(3.9) million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

(7) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $17.5 million, $5.8 million and $16.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

(9)

Adjusted income (loss) 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 (losses) from unconsolidated affiliates. Such amounts should not be used as a substitute for 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 (loss) derived from operating activities, because it believes that these financial measures are an accurate reflection of the ongoing profitability of our Company. A reconciliation of this non-GAAP measure to income (loss) before income taxes, which is a GAAP measure, is provided within the above table.

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

(11) Represents impairments and other charges recorded during the years ended December 31, 2009 and 2008, respectively.

(12) 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.

(13) International rig years include our equivalent percentage ownership of rigs owned by unconsolidated affiliates which totaled 2.5 years, 3.5 years and 4.0 years during the years ended December 31, 2009, 2008 and 2007, respectively.

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

(15) The percentage is so large that is not meaningful.

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:

	Year Ended December 31,			Increase/(Decrease)		
	2009	**2008**	**2007**	**2009 to 2008**		**2008 to 20**
sands, except percentages and rig activity)						
g revenues and Earnings from unconsolidated	$ 1,082,531	$ 1,878,441	$ 1,710,990	$ (795,910)	(42)%	$ 167,451
l income derived from operating activities	$ 294,679	$ 628,579	$ 596,302	$ (333,900)	(53)%	$ 32,277
s	149.4	247.9	229.4	(98.5)	(40)%	18.5

Operating results decreased from 2008 to 2009 primarily due to a decline in drilling activity, driven by lower natural gas prices beginning in the fourth quarter of 2008 and diminished demand as customers released rigs and delayed drilling projects in response to the significant drop in natural gas prices and the tightening of the credit markets. Operating results were further negatively impacted by higher depreciation expense related to capital expansion projects completed in recent years.

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.

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

	Year Ended December 31,			Increase/(Decrease)		
	2009	**2008**	**2007**	**2009 to 2008**		**2008 to 200**
usands, except percentages and rig activity)						
	$ 412,243	$ 758,510	$ 715,414	$ (346,267)	(46)%	$ 43,096

ng revenues and Earnings from unconsolidated s						
d income derived from operating activities	$ 28,950	$ 148,626	$ 156,243	$ (119,676)	(81)%	$ (7,617)
rs	590,878	1,090,511	1,119,497	(499,633)	(46)%	(28,986)

Operating results decreased from 2008 to 2009 primarily due to lower rig utilization and price erosion, driven by lower customer demand for our services due to relatively lower oil prices caused by the U.S. economic recession and reduced end product demand. Operating results were further negatively impacted by higher depreciation expense related to capital expansion projects completed in recent years.

Operating revenues and Earnings from unconsolidated affiliates increased from 2007 to 2008 primarily as a result of higher average dayrates year-over-year, driven by high oil prices during 2007 and the majority of

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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 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:

	Year Ended December 31,			Increase/(Decrease)			
	2009	2008	2007	2009 to 2008		2008 to 2007	
housands, except percentages and rig activity)							
rating revenues and Earnings from unconsolidated ates	$ 157,305	$ 252,529	$ 212,160	$ (95,224)	(38)%	$ 40,369	1
sted income derived from operating activities	$ 30,508	$ 59,179	$ 51,508	$ (28,671)	(48)%	$ 7,671	1
years	11.0	17.6	15.8	(6.6)	(38)%	1.8	1

The decrease in operating results from 2008 to 2009 primarily resulted from lower average dayrates and utilization for the SuperSundowner™ platform rigs, workover jack-up rigs, barge drilling and workover rigs, and Sundowner® platform rigs, partially offset by higher utilization of our MODS® rigs inclusive of a significant term contract for a MODS® rig deployed in January 2009.

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.

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

	Year Ended December 31,			Increase/(Decrease)			
	2009	2008	2007	2009 to 2008		2008 to 2007	
thousands, except percentages and rig activity)							
erating revenues and Earnings from unconsolidated iates	$ 204,407	$ 184,243	$ 152,490	$ 20,164	11%	$ 31,753	2
usted income derived from operating activities	$ 62,742	$ 52,603	$ 37,394	$ 10,139	19%	$ 15,209	4
years	10.0	10.9	8.7	(0.9)	(8)%	2.2	2

The increases in operating results from 2008 to 2009 and from 2007 to 2008 were primarily due to increases in average dayrates and drilling activity. Although drilling activity levels decreased slightly during 2009, operating results reflect the higher average margins as a result of the addition of some high specification rig work. Drilling activity levels increased in 2008 as a result of the deployment and utilization of rigs added to the fleet in late 2007 under long-term contracts. The increases during 2009 and 2008 have been partially offset by higher operating costs and increased depreciation expense as well as increased labor and repairs and maintenance costs in 2009 and 2008 as compared to prior years.

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

	Year Ended December 31,			Increase/(Decrease)		
	2009	2008	2007	2009 to 2008		2008 to 2007
usands, except percentages and rig activity)						
ng revenues and Earnings from unconsolidated es	$ 298,653	$ 502,695	$ 545,035	$ (204,042)	(41)%	$ (42,340)
ed income (loss) derived from operating es	$ (7,019)	$ 61,040	$ 87,046	$ (68,059)	(111)%	$ (26,006)
rs Drilling	19.7	35.5	36.7	(15.8)	(45)%	(1.2)
urs Well-servicing	143,824	248,032	283,471	(104,208)	(42)%	(35,439)

Operating results decreased from 2008 to 2009 primarily as a result of an overall decrease in drilling and well-servicing activity due to lower natural gas prices driving a significant decline of customer demand for drilling and well-servicing operations. Our operating results for 2009 were further negatively impacted by the economic uncertainty in the Canadian drilling market and financial market instability. The Canadian dollar began 2009 in a weak position versus the U.S. dollar, during a period of time when drilling and well-servicing activity was typically at its seasonal peak, which also had an overall negative impact on operating results. These decreases in operating results were partially offset by cost reductions in direct costs, general and administrative expenses and depreciation.

The decrease in operating results from 2007 to 2008 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 which led to 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.

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

	Year Ended December 31,			Increase/(Decrease)		
	2009	2008	2007	2009 to 2008		2008 to 20
sands, except percentages and rig activity)						
g revenues and Earnings from unconsolidated	$ 1,265,097	$ 1,372,168	$ 1,094,802	$ (107,071)	(8)%	$ 277,366
l income derived from operating activities	$ 365,566	$ 407,675	$ 332,283	$ (42,109)	(10)%	$ 75,392
s	100.2	120.5	115.2	(20.3)	(17)%	5.3

The decrease in operating results from 2008 to 2009 resulted primarily from year-over-year decreases in average dayrates and lower utilization of rigs in Mexico, Libya, Argentina and Colombia, driven by weakening customer demand for drilling services stemming from the drop in oil prices in the fourth quarter of 2008 which continued throughout 2009. Operating results were further negatively impacted by higher depreciation expense related to capital expansion projects completed in recent years. These decreases were partially offset by higher average dayrates from two jack-up rigs deployed in Saudi Arabia, increases in average dayrates for our new and incremental rigs added and deployed during 2008 and a start-up floating, drilling, production, storage and offloading vessel off the coast of the Republic of the Congo.

The increase in operating results from 2007 to 2008 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. Operating results during 2007 and most of 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 were 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. The results of operations for this reportable segment are as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2009	2008	2007	2009 to 2008		2008 to 2007	
(In thousands, except percentages)							
Operating revenues and Earnings (losses) from unconsolidated affiliates	$ (209,091)	$ (151,465)	$ 152,320	$ (57,626)	(38)%	$ (303,785)	(199)%
Adjusted income (loss) derived from operating activities	$ (256,535)	$ (206,490)	$ 97,150	$ (50,045)	(24)%	$ (303,640)	(313)%

Our operating results decreased from 2008 to 2009 primarily as a result of full-cost ceiling test writedowns recorded during 2009 by our unconsolidated joint ventures. During 2009, our U.S., international and Canadian oil and gas joint ventures recorded full-cost ceiling test writedowns, of which our proportionate share totaled $237.1 million. These writedowns 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 was evaluated using the 12-month average commodity price as required by the revised SEC rules.

Operating results further decreased from 2008 to 2009 due to declines in natural gas prices and production volumes from our Ramshorn and joint venture operations. Additionally, operating results for 2008 included a $12.3 million gain recorded on the sale of leasehold interests.

Our operating results decreased from 2007 to 2008 as a result of full-cost ceiling test writedowns recorded during 2008 by our unconsolidated oil and gas joint ventures. During 2008, our U.S., international and Canadian oil and gas joint ventures recorded full-cost ceiling test writedowns, of which our proportionate share totaled $228.3 million. The full-cost ceiling test was determined using the single-day, year-end price as required by SEC rules at the time.

Additionally during 2008, our proportionate share of losses from our unconsolidated 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 its forward contracts to minimize the volatility in reported earnings caused by market price fluctuations of the underlying hedged commodities. These losses were 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 leasehold interests in 2008.

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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:

(In thousands, except percentages)	Year Ended December 31, 2009	2008	2007	Increase/(Decrease) 2009 to 2008		2008 to 2007	
Operating revenues and Earnings from unconsolidated affiliates	$ 446,282	$ 683,186	$ 588,483	$ (236,904)	(35)%	$ 94,703	16%
Adjusted income derived from operating activities	$ 34,120	$ 68,572	$ 35,273	$ (34,452)	(50)%	$ 33,299	94%

The decreases in operating results from 2008 to 2009 primarily resulted from (i) lower demand in the U.S. and Canadian drilling markets for rig instrumentation and data collection services from oil and gas exploration companies, (ii) decreases in customer demand for our construction and logistics services in Alaska and (iii) decreased capital equipment unit volumes and lower service and rental activity as a result of the slowdown in the oil and gas industry.

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

Discontinued Operations

In 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 some related assets, including rights under a vessel construction contract. We have not had any continuing involvement subsequent to the sale of this business and have accounted for the Sea Mar business as discontinued operations in the accompanying audited consolidated statements of income (loss). Our condensed statement of income from discontinued operations related to the Sea Mar business for the year ended December 31, 2007 was as follows:

(In thousands, except percentages)	Year Ended December 31, 2007
Revenues	$ 58,887
Income from discontinued operations, net of tax	$ 35,024

OTHER FINANCIAL INFORMATION

General and administrative expenses

	Year Ended December 31,	Increase/(Decrease)

(In thousands, except percentages)	2009	2008	2007	2009 to 2008		2008 to 2007	
General and administrative expenses	$ 429,663	$ 479,984	$ 436,282	$ (50,321)	(10)%	$ 43,702	10%
General and administrative expenses as a percentage of operating revenues	11.6%	8.7%	8.8%	2.9%	33%	(.1)%	(1%)

General and administrative expenses decreased from 2008 to 2009 primarily as a result of significant decreases in wage-related expenses and other cost-reduction efforts across all business units, partially offset by an increase of approximately $61.2 million in stock compensation expense. During 2009, share-based compensation expense included $72.1 million of compensation expense related to previously granted restricted stock and option awards held by Messrs. Isenberg and Petrello that was unrecognized as of April 1, 2009. The recognition of this expense resulted from provisions of their respective new employment agreements that effectively eliminated the risk of forfeiture of such awards. There is no remaining unrecognized expense related to their outstanding restricted stock and option awards. General and administrative expenses as a percentage of operating revenues increased primarily due to lower revenues.

General and administrative expenses increased from 2007 to 2008 primarily as a result of increases in wages and wage-related expenses for a majority of our operating segments compared to each prior year, which resulted from an increase in the number of employees required to support higher activity levels. The increase was also driven by higher compensation expense, primarily resulting from higher bonuses and non-cash compensation expenses recorded for restricted stock awards during 2007 and 2008.

Depreciation and amortization, and depletion expense

	Year Ended December 31,			Increase/(Decrease)			
	2009	2008	2007	2009 to 2008		2008 to 2007	
(In thousands, except percentages)							
Depreciation and amortization expense	$ 668,415	$ 614,367	$ 469,669	$ 54,048	9%	$ 144,698	31%
Depletion expense	$ 11,078	$ 25,442	$ 31,165	$ (14,364)	(56)%	$ (5,723)	(18)%

Depreciation and amortization expense. Depreciation and amortization expense increased from 2008 to 2009 and from 2007 to 2008 primarily as a result of projects completed in recent years under our expanded capital expenditure program that commenced in early 2005.

Depletion expense. Depletion expense decreased from 2008 to 2009 and from 2007 to 2008 primarily as a result of decreased natural gas production volumes during each year.

Interest expense

	Year Ended December 31,			Increase/(Decrease)			
	2009	2008	2007	2009 to 2008		2008 to 2007	
(In thousands, except percentages)							
Interest expense	$ 264,948	$ 196,718	$ 154,920	$ 68,230	35%	$ 41,798	27%

Interest expense increased from 2008 to 2009 as a result of the interest expense related to our January 2009 issuance of 9.25% senior notes due January 2019. The increase was partially offset by a reduction to interest expense due to our repurchases of approximately $1.1 billion par value of 0.94% senior exchangeable notes during 2008 and 2009.

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.

Investment income (loss)

	Year Ended December 31,			Increase/(Decrease)

(In thousands, except percentages)	2009	2008	2007	2009 to 2008		2008 to 2007	
Investment income (loss)	$ 25,756	$ 21,726	$ (15,891)	$ 4,030	19%	$ 37,617	237%

Investment income during 2009 was $25.8 million compared to $21.7 million during the prior year. Investment income in 2009 included net unrealized gains of $9.8 million from our trading securities and interest and dividend income of $15.9 million from our cash, other short-term and long-term investments.

Investment income during 2008 was $21.7 million compared to a net investment loss of $15.9 million during the prior year. Investment income in 2008 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.

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Investment income (loss) during 2007 included a net loss of $61.4 million from our actively managed funds classified as long-term investments inclusive of substantial gains from sales of our marketable equity securities. This net loss was offset by interest and dividend income of $45.5 million from our short-term investments.

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

(In thousands, except percentages)	Year Ended December 31, 2009	2008	2007	Increase/(Decrease) 2009 to 2008		2008 to 2007	
Gains(losses) on sales and retirements of long-lived assets and other income (expense), net	$ (12,962)	$ (15,027)	$ (11,315)	$ 2,065	14%	$ (3,712)	(33)%

The amount of gains (losses) on sales and retirements of long-lived assets and other income(expense), net for 2009 represents a net loss of $13.0 million and includes: (i) foreign currency exchange losses of approximately $8.4 million, (ii) increases of litigation expenses of $11.5 million, and (iii) net losses on sales and retirements of long-lived assets of approximately $5.9 million. These losses were partially offset by pre-tax gains of $11.5 million recognized on purchases of $964.8 million par value of our 0.94% senior exchangeable notes due 2011.

The amount of gains (losses) on sales and retirements of long-lived assets and other income(expense), net for 2008 represents a net loss of $15.0 million and includes: (i) 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, (ii) losses on retirements 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 (iii) increases of litigation expenses of $3.5 million. These losses were partially offset by a $12.2 million pre-tax gain recognized on our purchase of $100 million par value of 0.94% senior exchangeable notes due 2011.

The amount of gains (losses) on sales and retirements of long-lived assets and other income(expense), net for 2007 represents a net loss of $11.3 million and includes: (i) losses on retirements and impairment charges on long-lived assets of approximately $40.0 million and (ii) increases of litigation expenses 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.

Impairments and Other Charges

(In thousands, except percentages)	Year Ended December 31, 2009	2008	2007	Increase/(Decrease) 2009 to 2008		2008 to 2007	
Goodwill impairments	$ 14,689	$ 150,008	$	$ (135,319)	(90)%	$ 150,008	100%
Impairment of long-lived assets to be disposed of other than by sale	64,229			64,229	100%		
Impairment of other intangible assets		4,578		(4,578)	(100)%	4,578	100%
Impairment of oil and gas- related assets	205,897	21,537	41,017	184,360	856%	(19,480)	(47)%

Other-than-temporary impairment on securities	54,314			54,314	100%		
Total	$ 339,129	$ 176,123	$ 41,017	$ 163,006	93%	$ 135,106	329%

During the years ended December 31, 2009 and 2008, we recognized goodwill impairments of approximately $14.7 million and $150.0 million, respectively, related to our Canadian operations. During 2008, we impaired the entire goodwill balance of $145.4 million of our Canada Well-servicing and Drilling operating segment and recorded an impairment of $4.6 million to Nabors Blue Sky Ltd., one of our Canadian subsidiaries reported in our Other Operating segments. During 2009, we impaired the remaining goodwill balance of $14.7 million of Nabors Blue Sky Ltd. The impairment charges resulted from of our annual impairment tests on goodwill which compared the estimated fair value of each of our reporting units to its carrying value. The estimated fair value of these business units was determined using discounted cash flow models involving assumptions based on our utilization of rigs or aircraft, revenues and earnings from affiliates, as well as direct costs, general and administrative costs, depreciation, applicable income taxes, capital expenditures and working capital requirements. The impairment charges were deemed necessary due to the continued downturn in the oil and gas industry in Canada and the lack of certainty regarding eventual recovery in the value of these operations. This downturn has led to reduced capital spending by some of our customers and has diminished demand for our drilling services and for immediate access to remote drilling sites. A significantly prolonged period of lower oil and natural gas prices could adversely affect the demand for and prices of our services, which could result in future goodwill impairment charges for other reporting units due to the potential impact on our estimate of our future operating results. See Critical Accounting Policies below and Note 2 Summary of Significant Accounting Policies (included under the caption Goodwill) in Part II, Item 8. Financial Statements and Supplementary Data.

During the year ended December 31, 2009, we retired some rigs and rig components in our U.S. Offshore, Alaska, Canada and International Contract Drilling segments and reduced their aggregate carrying value from $69.0 million to their estimated aggregate salvage value, resulting in impairment charges of approximately $64.2 million. The retirements included inactive workover jack-up rigs in our U.S. Offshore and International operations, the structural frames of some incomplete coiled tubing rigs in our Canada operations and miscellaneous rig components in our Alaska operations. The impairment charges resulted from the continued deterioration and longer than expected downturn in the demand for oil and gas drilling activities. A prolonged period of lower natural gas and oil prices and its potential impact on our utilization and dayrates could result in the recognition of future impairment charges to additional assets if future cash flow estimates, based upon information then available to management, indicate that the carrying value of those assets may not be recoverable.

Also in 2009, we recorded impairments totaling $205.9 million to some of the oil and gas-related assets of our wholly owned Ramshorn business unit. We recorded an impairment of $149.1 million to one of our oil and gas financing receivables, which reduced the carrying value of our oil and gas financing receivables recorded as long-term investments to $92.5 million. The impairment resulted primarily from commodity price deterioration and the lower price environment lasting longer than expected. This prolonged period of lower prices has significantly reduced demand for future gas production and development in the Barnett Shale area of north central Texas, which has influenced our decision not to expend capital to develop on some of the undeveloped acreage. The impairment was determined using discounted cash flow models involving assumptions based on estimated cash flows for proved and probable reserves, undeveloped acreage value, and current and expected natural gas prices. We believe the estimates used provide a reasonable estimate of current fair value. A further protraction or continued period of lower commodity prices could result in recognition of future impairment charges. During the years ended December 31, 2009, 2008 and 2007, our impairment tests on the oil and gas properties of our wholly owned Ramshorn business unit resulted in impairment charges of $56.8 million, $21.5 million and $41.0 million, respectively. The impairments recognized during 2009 were primarily the result of a write down of the carrying value of some acreage in the U.S. and Canada because we do not have future plans to develop. The impairments recognized during 2008 were primarily due to the significant decline in oil and natural gas prices at the end of 2008. The impairments recognized during 2007 were necessary from lower than expected performance of some oil and gas development wells. Additional discussion of our policy pertaining to the calculations of these impairments is set forth in Oil and Gas Properties under Critical Accounting Estimates below in this section or in Note 2 Summary of Significant Accounting Policies in Part II Item 8. Financial Statements and Supplementary Data.

In 2009, we recorded other-than-temporary impairments to our available-for-sale securities totaling $54.3 million. Of this, $35.6 million was related to an investment in a corporate bond that was downgraded to non-investment grade level by Standard and Poor s and Moody s Investors Service during the year. Our determination that the impairment was other than temporary was based on a variety of factors, including the length of time and extent to which the market value had been less than cost, the financial condition of the issuer of the security, and the credit ratings and recent reorganization of the issuer. The remaining $18.7 million related to an equity security of a public company whose operations are driven in large measure by the price of oil and in which we invested approximately $46 million during the second and third quarters of 2008. During late 2008, demand for oil and gas began to diminish significantly as part of the general deterioration of the global economic environment, causing a broad decline in value of nearly all oil and gas-related equity securities. Because the trading price per share of this security remained below our cost basis for an extended period, we determined the investment was other than temporarily impaired and it was appropriate to write down the investment s carrying value to its current estimated fair value of approximately $27.0 million at December 31, 2009.

Income tax rate

	Year Ended December 31,			**Increase/(Decrease)**			
	2009	**2008**	**2007**	**2009 to 2008**		**2008 to 2007**	
Effective income tax rate from continuing operations	64%	30%	20%	34%	113%	10%	50%

Our effective income tax rate for 2009 reflects the disparity between losses in our U.S. operations (attributable primarily to impairments) and income in our other operations primarily in lower tax jurisdictions. Because the U.S. income tax rate is higher than that of other jurisdictions, the tax benefit from our U.S. losses was not proportionately reduced by the tax expense from our other operations. The result is a net tax benefit that represents a significant percentage (63.5%) of our consolidated loss before income taxes. Because of the manner in which this number is derived, we do not believe it presents a meaningful basis for comparing our 2009 effective income tax rate to our 2008 effective income tax rate.

The increase in our effective income tax rate from 2007 to 2008 resulted from (1) our goodwill impairments which 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 2008 taxable income being generated in the United States, which generally imposes a higher tax rate than the other jurisdictions in which we operate.

We are subject to income taxes in the U.S. and numerous other jurisdictions. Significant judgment is required in determining our worldwide provision for income taxes. One of the most volatile factors in this determination is the relative proportion of our income or loss being recognized in high versus low tax jurisdictions. In the ordinary course of our business, there are many transactions and calculations for which the ultimate tax determination is uncertain. We are regularly under audit by tax authorities. Although we believe our tax estimates are reasonable, the final outcome of tax audits and any related litigation could be materially different than what is reflected in our income tax provisions and accruals. The results of an audit or litigation could materially affect our financial position, income tax provision, net income, or cash flows.

Various bills have been introduced in Congress that 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 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 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 impact on our ability to realize the tax savings recorded to date as well as future tax savings resulting from our reorganization.

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, 2009 and 2008.

Operating Activities. Net cash provided by operating activities totaled $1.6 billion during 2009 compared to net cash provided by operating activities of $1.5 billion during 2008. Net cash provided by operating activities (operating cash flows) is our primary source of capital and liquidity. Factors affecting changes in operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as depreciation and amortization, depletion, impairments, share-based compensation, deferred income taxes and our proportionate share of earnings or losses from unconsolidated affiliates. Net income (loss) adjusted for non-cash components was approximately $1.1 billion and $1.7 billion for the years ended December 31, 2009 and 2008, respectively. Additionally, changes in working capital items such as collection of receivables can be a significant component of operating cash flows. Changes in working capital items provided $471.9 million in cash flows for the year ended December 31, 2009 and required $278.6 million in cash flows for the year ended December 31, 2008.

Investing Activities. Net cash used for investing activities totaled $1.2 billion during 2009 compared to net cash used for investing activities of $1.5 billion during 2008. During 2009 and 2008, cash was used primarily for capital expenditures totaling $1.1 billion and $1.5 billion, respectively, and investments in unconsolidated affiliates totaling $125.1 million and $271.3 million, respectively. During 2009 and 2008, cash was derived from sales of investments, net of purchases, totaling $24.4 million and $251.6 million, respectively.

Financing Activities. Net cash provided by financing activities totaled $19.4 million during 2009 compared to net cash used for financing activities of $89.2 million during 2008. During 2009, cash was derived from the receipt of $1.1 billion in proceeds, net of debt issuance costs, from the January 2009 issuance of 9.25% senior notes due 2019. Also during 2009, cash totaling $862.6 million was used to purchase $964.8 million par value of 0.94% senior exchangeable notes due 2011 and cash totaling $225.2 million was used to redeem the 4.875% senior notes. During 2008, cash totaling $836.5 million was used to redeem Nabors Delaware s zero coupon senior exchangeable notes due 2023 and zero coupon senior convertible debentures due 2021 and for the purchase of $100 million par value of 0.94% senior exchangeable notes due 2011 in the open market. During 2008, cash was used to repurchase our common shares in the open market for $281.1 million. Also during 2008, cash was provided by the receipt of $955.6 million in net proceeds from the February and July 2008 issuances of the 6.15% senior notes due 2018, net of debt issuance costs. During 2009 and 2008, cash was provided by our receipt of proceeds totaling $11.2 million and $56.6 million, respectively, from the exercise by our employees of options to acquire our common shares.

Future Cash Requirements

As of December 31, 2009, we had long-term debt, including current maturities, of $3.9 billion and cash and investments of $1.2 billion, including $100.9 million of long-term investments and other receivables. Long-term investments and other receivables include $92.5 million in oil and gas financing receivables.

Our 0.94% senior exchangeable notes mature in May 2011. During 2008 and 2009 collectively, we purchased $1.1 billion par value of these notes in the open market for cash totaling $938.4 million, leaving approximately

$1.7 billion par value outstanding. The balance of these notes will be reclassified to current debt in the second quarter of 2010. We believe our positive cash flow from operations in combination with our

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ability to access the capital markets will be sufficient to enable us to satisfy the payment obligation due in May 2011.

Our 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 24, 2010, the closing market price for our common stock was $21.92 per share. 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 before maturity in May 2011, 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 the price of our shares were to exceed $59.57 for the required period of time, 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.

As of December 31, 2009, we had outstanding purchase commitments of approximately $152.4 million, primarily for rig-related enhancements, construction and sustaining capital expenditures and other operating expenses. Capital expenditures over the next twelve months, including these outstanding purchase commitments, are currently expected to total approximately $.6 $.8 billion, including currently planned rig-related enhancements, 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. These programs, which are nearing an end, 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. The expansion of our capital expenditure programs to build new state-of-the-art drilling rigs has impacted 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 issuing 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 below under Off-Balance Sheet Arrangements (Including Guarantees).

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The following table summarizes our contractual cash obligations as of December 31, 2009:

	Payments Due by Period				
(In thousands)	Total	< 1 Year	1-3 Years	3-5 Years	Thereafter
Contractual cash obligations:					
Long-term debt:(1)					
Principal	$ 4,061,255	$ 163	$ 1,961,002(2)	$ 90	$ 2,100,000(3)
Interest	1,566,550	194,679	365,645	328,076	678,150
Operating leases(4)	35,550	15,498	13,705	4,840	1,507
Purchase commitments(5)	152,387	151,097	1,290		
Employment contracts(4)	35,442	10,723	21,330	3,389	
Pension funding obligations(6)	450	450			
Total contractual cash obligations	$ 5,851,634	$ 372,610	$ 2,362,972	$ 336,395	$ 2,779,657

The table above excludes liabilities for unrecognized tax benefits totaling $107.5 million as of December 31, 2009 because we are unable to make reasonably reliable estimates of the timing of cash settlements with the respective taxing authorities. Further details on the unrecognized tax benefits can be found in Note 12 Income Taxes in Part II, Item 8. Financial Statements and Supplementary Data.

(1) See Note 11 Debt in Part II, Item 8. Financial Statements and Supplementary Data.

(2) Includes the remaining portion of Nabors Delaware s 0.94% senior exchangeable notes due May 2011 and 5.375% senior notes due August 2012.

(3) Represents Nabors Delaware s aggregate 6.15% senior notes due February 2018 and 9.25% senior notes due January 2019.

(4) See Note 16 Commitments and Contingencies in Part II, Item 8. - Financial Statements and Supplementary Data.

(5) 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.

(6) See Note 14 Pension, Postretirement and Postemployment Benefits 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, both 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. Through December 31, 2009, $464.5 million of our common shares had been repurchased under this program. As of December 31, 2009, 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 16 Commitments and Contingencies in Part II, Item 8. Financial Statements and Supplementary Data for discussion of commitments and contingencies relating to (i) new employment agreements, effective April 1, 2009, that could result in significant cash payments of $100 million and $50 million to Messrs. Isenberg and Petrello, respectively, by the Company if their employment is terminated in the event of death or disability or cash payments of $100 million and $45 million to Messrs. Isenberg and Petrello, respectively, by the Company if their employment is terminated without cause or in the event of a change in control 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, 2009, we had cash and investments of $1.2 billion (including $100.9 million of long-term investments and other receivables, inclusive of $92.5 million in oil and gas financing receivables) and working capital of $1.6 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. This compares to cash and investments of $824.2 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 as of December 31, 2008.

Our gross funded debt to capital ratio was 0.41:1 as of each December 31, 2009 and 2008. Our net funded debt to capital ratio was 0.33:1 as of December 31, 2009 and 0.35:1 as of December 31, 2008.

The gross funded debt to capital ratio is calculated by dividing (x) funded debt by (y) funded debt *plus* deferred tax liabilities (net of deferred tax assets) *plus* capital. Funded debt is the sum of (1) short-term borrowings, (2) the current portion of long-term debt and (3) long-term debt. Capital is shareholders equity.

The net funded debt to capital ratio is calculated by dividing (x) net funded debt by (y) net funded debt *plus* deferred tax liabilities (net of deferred tax assets) *plus* capital. Net funded debt is funded debt *minus* the sum of cash and cash equivalents and short-term and long-term investments and other receivables. Both of these ratios are used to calculate a company s leverage in relation to its capital. Neither ratio measures operating performance or liquidity as defined by GAAP and, therefore, may not be comparable to similarly titled measures presented by other companies.

Our interest coverage ratio was 6.2:1 as of December 31, 2009 and 20.7:1 as of December 31, 2008. The interest coverage ratio is a trailing 12-month quotient of the sum of net income (loss) attributable to Nabors, interest expense, depreciation and amortization, depletion expense, impairments and other charges, income tax expense (benefit) and our proportionate share of writedowns from our unconsolidated oil and gas joint ventures *less* investment income (loss) divided by cash interest expense. This ratio is a method for calculating the amount of operating cash flows available to cover cash interest expense. The interest coverage 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.

We had four letter of credit facilities with various banks as of December 31, 2009. Availability under our credit facilities as of December 31, 2009 was as follows:

(In thousands)	
Credit available	$ 245,442
Letters of credit outstanding, inclusive of financial and performance guarantees	(71,389)
Remaining availability	$ 174,053

Our ability to access capital markets or to otherwise obtain sufficient financing is enhanced by our senior unsecured debt ratings as provided by Fitch Ratings, Moody s Investors Service and Standard & Poor s, which are currently BBB+ , Baa1 and BBB+ , respectively, and our historical ability to access those markets as needed. While there can be no assurances that we will be able to access these markets in the future, we believe that we will be able to access capital markets or otherwise obtain financing in order to satisfy any payment obligation that might arise upon exchange or purchase of our notes and that any cash payment due of this magnitude, in addition to our other cash obligations, would not ultimately have a material adverse impact on our liquidity or financial position. In addition, Standard & Poor s recently affirmed its BBB+ credit rating, but revised its outlook to negative from stable in early 2009 due primarily to worsening industry conditions. A credit downgrade may impact our ability to access credit markets.

Our current cash and investments and projected cash flows from 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.

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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.

Off-Balance Sheet Arrangements (Including Guarantees)

We are a party to some 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 under 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, which serve as guarantees, to some third parties. 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 guarantees issued by Nabors and guarantees representing contingent consideration in connection with a business combination:

	Maximum Amount				
	2010	**2011**	**2012**	**Thereafter**	**Total**
(In thousands)					
Financial standby letters of credit and other financial surety instruments	$ 66,182	$ 10,808	$ 277	$	$ 77,267
Contingent consideration in acquisition		4,250			4,250
Total	$ 66,182	$ 15,058	$ 277	$	$ 81,517

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 unemployment benefits to former employees and other social welfare provisions. The Stimulus Act has not had a significant impact on our consolidated financial statements.

A court in Algeria entered a judgment of approximately $19.7 million against us related to alleged customs infractions in 2009. We believe we did not receive proper notice of the judicial proceedings, and that the amount of the judgment is excessive. We have asserted the lack of legally required notice as a basis for challenging the judgment on appeal to the Algeria Supreme Court. 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 and the timing thereof are 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 $19.7 million.

Recent Accounting Pronouncements

On July 1, 2009, the Financial Accounting Standards Board (FASB) released the Accounting Standards Codification (ASC). The ASC became the single source of authoritative nongovernmental GAAP. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. The ASC is not intended to change GAAP, but changes the approach by referencing authoritative literature by topic (each, a Topic) rather than by type of standard. Accordingly, references in the Notes to Consolidated Financial Statements to former FASB positions, statements, interpretations, opinions, bulletins or other pronouncements are now presented as references to the corresponding Topic in the ASC.

Effective January 1, 2009, Nabors changed its method of accounting for certain of its convertible debt instruments in accordance with the revised provisions of the Debt with Conversions and Other Options Topic of the ASC. Additionally, Nabors changed its method for calculating its basic and diluted earnings per share using the two-class method in accordance with the revised provisions of the Earnings Per Share Topic of the ASC. As required by the Accounting Changes and Error Corrections Topic of the ASC, financial information and earnings per share calculations for prior periods have been adjusted to reflect retrospective application.

The revised provisions of the Debt with Conversions and Other Options Topic clarify that convertible debt instruments that may be settled in cash upon conversion are 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 proceeds related to the conversion option and is recorded as capital in excess of par value. The liability is recorded at a discount, which is then amortized as additional non-cash interest expense over the convertible debt instrument s expected life. The retrospective application and impact of these provisions on our consolidated financial statements is described in Note 11 Debt in Part II Item 8. Financial Statements and Supplementary Data.

The revised provisions relating to use of the two-class method for calculating earnings per share within the Earnings Per Share Topic provide 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. Our awards of restricted stock are considered participating securities under this definition. The retrospective application and impact of these provisions on our consolidated financial statements is set forth in Note 17 Earnings (Losses) Per Share in Part II Item 8. Financial Statements and Supplementary Data.

Effective January 1, 2008, we adopted and applied the provisions of the Fair Value Measurements and Disclosures Topic of the ASC to our financial assets and liabilities and on January 1, 2009 applied the same provisions to our nonfinancial assets and liabilities. Effective April 1, 2009, we adopted the provisions of this Topic relating to fair value measures in inactive markets. The provisions provide additional guidance for determining whether a market for a financial asset is not active and a transaction is not distressed for fair value measurements. The application of these provisions did not have a material impact on our consolidated financial statements. Our fair value disclosures are provided in Note 5 Fair Value Measurements in Part II Item 8. Financial Statements and Supplementary Data.

Effective January 1, 2009, we adopted the revised provisions of the Business Combinations Topic of the ASC and will apply those provisions on a prospective basis to acquisitions. The revised provisions retain the fundamental requirement that the acquisition method of accounting be used for all business combinations and expands the use of the acquisition method 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. The revised provisions require measurement at the acquisition date of the fair value of assets acquired, liabilities assumed and any noncontrolling interests. Additionally, acquisition-related costs, including restructuring costs, are recognized as expense separately from the acquisition.

Effective January 1, 2009, new provisions relating to noncontrolling interests of a subsidiary within the Identifiable Assets and Liabilities, and Any Noncontrolling Interest Topic of the ASC were released. The provisions establish the accounting and reporting standards for a noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. The provisions clarify 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. Our consolidated financial statements reflect the adoption and have been adjusted to reflect retrospective application. The application of these provisions did not have a material impact on our consolidated financial statements.

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Effective January 1, 2009, we adopted the revised provisions relating to expanded disclosures of derivatives within the Derivatives and Hedging Topic of the ASC. The revised provisions are intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced qualitative and quantitative disclosures regarding such instruments, gains and losses thereon and their effects on an entity s financial position, financial performance and cash flows. The application of these provisions did not have a material impact on our consolidated financial statements.

In December 2008, the SEC issued a Final Rule, Modernization of Oil and Gas Reporting. This rule revises some of the oil and gas reporting disclosures in Regulation S-K and Regulation S-X under the Securities Act and the Exchange Act, as well as Industry Guide 2. Effective December 31, 2009, the FASB issued revised guidance that substantially aligned the oil and gas accounting disclosures with the SEC s Final Rule. 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 12-month average natural gas and oil prices when calculating the quantities of proved reserves and performing the full-cost ceiling test calculation. The new standard also clarified that an entity s equity method investments must be considered in determining whether it has significant oil and gas activities. The disclosure requirements are effective for registration statements filed on or after January 1, 2010 and for annual financial statements filed on or after January 1, 2010. The FASB provided a one-year deferral of the disclosure requirements if an entity became subject to the requirements because of a change to the definition of significant oil and gas activities. When operating results from our wholly owned oil and gas activities are considered with operating results from our unconsolidated oil and gas joint ventures, which we account for under the equity method of accounting, we have significant oil and gas activities under the new definition. In line with the one-year deferral, we will provide the oil and gas disclosures in annual periods beginning after December 31, 2009.

Effective April 1, 2009, we adopted the provisions in the Investments of Debt and Equity Securities Topic of the ASC relating to recognition and presentation of other-than-temporary impairments to debt securities. The impact of these provisions is provided in Notes 3 Impairments and Other Charges and 4 Cash, Cash Equivalents and Investments in Part II Item 8. Financial Statements and Supplementary Data.