NABORS INDUSTRIES LTD
Form 10-K
February 29, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

¨ **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	**980363970**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*
Crown House Second Floor	
4 Par-la-Ville Road	
Hamilton, HM08	
Bermuda	**N/A**
(Address of principal executive offices)	*(Zip Code)*

(441) 292-1510

(Registrant s telephone number, including area code)

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

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

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

None.

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES þ NO ¨

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 ¨ 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 ¨

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 ¨

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.

Large Accelerated Filer þ Accelerated Filer ¨ Non-accelerated Filer ¨ Smaller Reporting Company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ¨ NO þ

The aggregate market value of the 265,089,538 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, 2011, of $24.64 per share as reported on the New York Stock Exchange, was $6,531,806,216. 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, 2012 was 288,679,432.

DOCUMENTS INCORPORATED BY REFERENCE (to the extent indicated herein)

Specified portions of the definitive Proxy

Statement to be distributed in connection with our 2012 Annual General Meeting of Shareholders (Part III).

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NABORS INDUSTRIES LTD.

Form 10-K Annual Report

For the Year Ended December 31, 2011

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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, as amended (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 relating 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, as amended (the Securities Act), and Section 21E of the Exchange Act. These forward-looking statements are based on an analysis of currently available competitive, financial and economic data and our operating plans. They are inherently uncertain and investors should recognize that events and actual results could turn out to be significantly different from our expectations. By way of illustration, when used in this document, words such as anticipate, believe, expect, plan, intend, estimate, project, will, should, could, may, predict and similar expressions a 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 possibility of changes in tax and other laws and regulations;
- the possibility of political instability, war or acts of terrorism; 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 that has a material impact on exploration, development or 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 mean Nabors Industries Ltd., together with our subsidiaries where the context requires, including Nabors Industries, Inc., a Delaware corporation (Nabors Delaware).

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PART I

ITEM 1. *BUSINESS*

Introduction

Nabors is the largest land drilling contractor in the world and one of the largest land well-servicing and workover contractors in the United States and Canada:

- We actively market approximately 499 land drilling rigs for oil and gas land drilling operations in the U.S. Lower 48 states, Alaska, Canada, South America, Mexico, the Middle East, the Far East, the South Pacific, Russia and Africa.

- We actively market approximately 581 rigs for land well-servicing and workover work in the United States and approximately 174 rigs for land well-servicing and workover work in Canada.

We are also a leading provider of offshore platform workover and drilling rigs, and actively market 39 platform, 12 jackup and four barge rigs in the United States, including the Gulf of Mexico, and multiple international markets.

In addition to the foregoing services:

- We provide hydraulic fracturing, cementing, nitrogen and acid pressure pumping services with over 730,000 hydraulic horsepower in key basins throughout the United States and Canada.

- We offer a wide range of ancillary well-site services, including engineering, transportation and disposal, construction, maintenance, well logging, directional drilling, rig instrumentation, data collection and other support services in select U.S. and international markets.

- 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 have a 51% ownership interest in a joint venture in Saudi Arabia, which owns and actively markets nine rigs in addition to the rigs we lease to the joint venture.

- We have invested in oil and gas exploration, development and production activities through both our wholly owned subsidiaries and our oil and gas joint ventures in which we hold 49-50% ownership interests.

Nabors was formed as a Bermuda exempted 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 Crown House, 4 Par-la-Ville Road, Second Floor, Hamilton, HM08, Bermuda, and our phone number there is (441) 292-1510.

Our Rig Fleet

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

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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 using our fleet of cranes, loaders and transport vehicles or those of third-party service providers. Well-servicing rigs are typically self-propelled, while 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.

Jackup Rigs. Jackup 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 jackup 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 jackup rigs generally are subject to a maximum water depth of approximately 125 feet, while some of our jackup rigs may drill in water depths as shallow as 13 feet. Nabors also has deeper water jackup 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 22 Segment Information in Part II, Item 8. Financial Statements and Supplementary Data.

Types of Drilling Contracts

On land in the U.S. Lower 48 states and Canada, we typically enter into 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 contracted 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

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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).

Pressure Pumping Services

We provide a wide range of wellsite solutions to oil and natural gas companies, consisting primarily of technical pumping services, including hydraulic fracturing, a process sometimes used in the completion of oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and oil production, and down-hole surveying services. Other technical services include completion, production and rental tool services. Additionally, we provide fluid logistics services, including those related to the transportation, storage and disposal of fluids that are used in the drilling, development and production of hydrocarbons.

During the year ended December 31, 2011 approximately 2.9% of revenues from our Pressure Pumping operating segment came from a Nabors consolidated entity and an unconsolidated Nabors affiliate. Our proportionate share of any profits resulting from sales to affiliates were eliminated in consolidation.

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 activities, 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 required to complete a well when it is first drilled. The completion process may

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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

In our Oil and Gas operating segment, we have invested in oil and gas exploration, development and production operations in the United States, Canada and Colombia.

During 2007, three joint ventures were formed for operations in these areas. Our joint venture in Canada was dissolved in June 2011, and our joint venture in Colombia monetized its assets during 2011. In addition, we hold a 49.7% ownership interest in a U.S. entity, NFR Energy LLC (NFR Energy). We account for these investments using the equity method of accounting. Our joint ventures pursue 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 oil and gas exploration, development and production operations have focused on the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids in Alaska, Arkansas, California, Louisiana, Oklahoma, Mississippi, Montana, North Dakota, Texas, Utah and Wyoming. Outside of the United States, we own or have interests in the Canadian provinces of Alberta and British Columbia and in Colombia.

During the fourth quarter of 2011, we announced our intention to dispose of a significant portion of our oil and gas investment portfolio. In addition to the sales of certain of our oil and gas assets in Colombia during 2011, we sold our working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California.

Additional information about our oil and gas activities can be found in Part II, Item 2. Properties and Item 8. Notes 4 Discontinued Operations and 24 Supplemental Information on Oil and Gas Exploration and Production Activities.

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. We 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 ROCKIT™ directional drilling system 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. Ryan Directional Services, 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. Peak Oilfield Service Company (Peak), one of our subsidiaries in Alaska, 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. Peak also provides construction and maintenance for ice roads, pads, facilities, equipment, drill sites and pipelines. Nabors also has a 50%

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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.

Our Customers

Our customers include major oil and gas companies, national oil and gas companies and independent oil and gas companies. No customer accounted for more than 10% of our consolidated revenues in 2011 or 2010.

Our Employees

As of December 31, 2011, we employed approximately 26,080 people, of whom approximately 2,666 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 Canada and Alaska 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. In addition, our pressure pumping operations located in the Appalachian, Mid-Continent, and Rocky Mountain regions of the United States can be adversely affected by seasonal weather conditions, primarily in the spring, as many municipalities impose weight restrictions on the paved roads that lead to our jobsites due to the muddy conditions caused by spring thaws. Global warming could lengthen these periods of reduced activity, but we cannot currently estimate to what degree. Our overall financial results reflect the seasonal variations experienced in these operations. Seasonality does not materially impact the remaining portions of our business.

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, our 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 the exploration, development and production activities of 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. The number of available rigs exceeds demand in many of our markets, resulting in strong price competition. Many rigs can be readily moved from one region to another in response to changes in levels of activity, which may result in an oversupply of rigs in those areas. Many of the total available contracts are currently awarded on a bid basis, which further increases competition based on price. The land drilling, workover, pressure pumping 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 largely in balance in the

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United States and other 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 and the first half of 2010, this continued decline in drilling and related activity impacted our key markets. In the latter half of 2010 and during 2011, gas prices remained depressed, while oil prices steadily rose, which increased demand for our drilling and well-servicing activities in North America as the market shifted to oil-and liquids-rich shale plays. Gas prices are likely to remain weak throughout 2012, principally due to a warm winter exacerbated by increasing supply attributable to rigs associated with the increased oil- and liquids-rich production. Our International markets were much slower to respond to the improving oil prices of 2010 and early 2011 and were further dampened when we renewed three of the four expiring contracts relating to our Arabian Gulf jackup rigs at lower rates due to a more competitive market. Our International markets are improving, and the deployment of several large projects and other rigs returning to work should improve results in 2012.

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 our 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 our U.S. Land Well-servicing operating segment, we compete with Basic Energy Services, Inc., Key Energy Services, Inc., Complete Energy Services, Inc., Forbes Energy Services Ltd. and numerous other competitors having smaller regional or local rig operations. In Canada and U.S. Offshore, we compete with many firms of varying size, several of which have more significant operations in those areas than Nabors. Elsewhere, we compete directly with various contractors at each location where we operate. Our Pressure Pumping operating segment competes with small and mid-sized independent contractors, as well as major oilfield services companies with operations outside of the United States. We believe that the market for land drilling, well-servicing and workover and pressure pumping 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 three major manufacturers of top drives. Its largest competitors in that market are National Oilwell Varco, Inc. and Tesco Corporation. Its largest competitors in the manufacture of rig instrumentation systems are Pason Systems Inc. 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 principally competes with CH2M_Hill for drilling support services. Other competitors include ASR Energy Services and Alaska Frontier Constructors. Peak is one of the premier ice road contractors with the largest fleet of all terrain vehicles used during the winter exploration months. Alaska Interstate Construction principally competes with large general contractors, including Granite Construction Company and Quality Asphalt Paving & Sealcoating Inc. on public works projects and Alaska Frontier Constructors, ASRC and CH2M_Hill on resource development projects.

Our Business Strategy

Our strategy is to position Nabors to grow and prosper when market conditions are good and to mitigate adverse effects when market conditions are bad. We have maintained a financial posture that allows us to

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capitalize on market weakness and strength by adding to our business base, thereby enhancing our upside potential. The principal elements of our strategy to build shareholder value are to:

- Maintain a strong and flexible balance sheet;
- Take advantage of opportunities as they arise;
- Leverage our global infrastructure;
- Achieve superior health, safety and environmental performance;
- Achieve superior operational performance;
- Focus on delivering value-added services to our customers;
- Enhance and leverage our technology position; and
- Achieve returns well above our cost of capital.

Beginning in 2005, we took advantage of the robust rig market in the United States and elsewhere to obtain a high volume of contracts for newly constructed rigs. A large portion of these rigs are subject to long-term contracts with creditworthy customers with the most significant impact occurring in our U.S. Lower 48 Land 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 the first half of 2010 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. In the latter half of 2010, commodity prices strengthened and our drilling activity improved. During 2011, oil commodity prices steadily rose and the related impact on demand for our drilling and well-servicing activities increased especially in the oil- and liquids-rich shale plays. We believe the deployment of our newer and higher-margin rigs under long-term contracts enhances our competitive position as market conditions improve.

Our current focus is to improve flexibility in our balance sheet, increase earnings and reduce our net debt. We are evaluating each business line for its strategic fit, execution effectiveness and return hurdles. In addition, we are:

- Emphasizing term contracts and execution in core businesses;
- Imposing higher hurdles for new projects;
- Optimizing intra-company synergies and technological advancements;

Improving capital allocation and return on capital expenditures; and

Monetizing nonperforming and nonstrategic assets.

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 and gas 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 499 land drilling rigs, 755 rigs for land well-servicing and workover work in the United States and Canada, offshore platform rigs, jackup units, 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.

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

Acquisitions

In September 2010, we acquired through a tender offer and merger all of the outstanding common stock of Superior Well Services, Inc. (Superior) at a cash purchase price of $22.12 per share, or approximately $681.3 million in the aggregate. The purchase price was allocated to the net tangible and intangible assets acquired and liabilities assumed based on their fair value at the acquisition date. The excess of the purchase price over such fair values was $335.0 million and was recorded as goodwill. Superior provides a wide range of wellsite solutions to oil and natural gas companies, primarily technical pumping services and down-hole surveying services.

On December 31, 2010, we purchased the business of Energy Contractors LLC (Energy Contractors) for a total cash purchase price of $53.4 million. The assets were comprised of vehicles and rig equipment and are included in our U.S. Land Well-servicing operating segment. The purchase price was allocated to the net tangible and intangible assets acquired based on their preliminary fair value estimates as of December 31, 2010. The excess of the purchase price over the fair value of the assets acquired was recorded as goodwill in the amount of $4.2 million.

In June 2011, the equity owners of Stone Mountain Venture Partnership (SMVP) dissolved the partnership in Canada, and a proportionate share of the assets and liabilities were conveyed to us in exchange for our ownership interest. The assets are presented as held for sale and the operating results in discontinued operations for all periods presented.

On July 31, 2011, we paid $65 million in cash to acquire the remaining 50 percent equity interest of Peak, making it a wholly owned subsidiary on this date. Previously, we held a 50 percent equity interest with a carrying value of $38.1 million that we had accounted for as an equity method investment. As a result of the acquisition, we consolidated the assets and liabilities of Peak during the third quarter of 2011 based on their respective fair values. The excess of the estimated fair value of the assets and liabilities over the net carrying value of our previously held equity interest resulted in a gain of $13.1 million and is reflected in losses (gains) on sales and retirements of long-lived assets and other expense (income) for the year ended December 31, 2011.

Divestitures

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 years ended December 31, 2007 and before are accounted for as discontinued operations.

On April 28, 2011, we sold some of our wholly owned oil and gas assets, previously included in our oil and gas operating segment, in Colombia. We received proceeds of $89.2 million from this sale and recognized a gain of approximately $39.6 million.

During the second quarter of 2011, our unconsolidated oil and gas joint venture, Remora Energy International LP (Remora), completed sales of its oil and gas assets in Colombia. Remora received gross proceeds of approximately $333.1 million from these sales and made cash distributions to us in the amount of $143.0 million with a final distribution expected upon dissolution of the joint venture.

On December 14, 2011, we sold our 25% working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California. We received proceeds of approximately $71.6 million from the sale and a commitment from the purchaser to continue utilizing our rigs. We recognized a gain of approximately $7.2 million. These assets were previously included in our oil and gas operating segment.

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The accompanying consolidated statements of income (loss) and notes to the consolidated financial statements have been updated to retroactively reclassify the operating results of the divested assets as discontinued operations for all periods presented. See Note 4 Discontinued Operations for additional discussion in Part II, Item 8. Financial Statements and Supplementary Data.

Environmental Compliance

We do not currently anticipate that compliance with currently applicable environmental regulations and controls will significantly change our competitive position, capital spending or earnings during 2012. We believe we are in material compliance with applicable environmental rules and regulations, and the cost of such compliance is not material to our business or financial condition. For a more detailed description of the environmental laws and regulations applicable to our 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.

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. Volatility in oil and natural gas prices is likely to continue in the foreseeable 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, which could result in a corresponding decline in demand for our services. 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 sustained or further decline in oil and natural gas prices could adversely impact our cash forecast models used to determine whether the carrying value of our long-lived assets exceed our future cash flows, which could result in future impairment to our long-lived 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.

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

The substantial volatility and extended declines in oil and natural gas prices in recent years in response to a weakened global economic environment have adversely affected our results of operations. In addition, economic

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conditions have resulted in substantial uncertainty in the capital markets and both access to and terms of available financing. During 2009 through the first half of 2010, many of our customers curtailed their drilling programs, which, in many cases, resulted in a decrease in demand for drilling rigs and a reduction in dayrates and utilization. Additionally, some customers 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.

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. There can also be adverse tax consequences associated with paying dividends.

We have a substantial amount of debt outstanding

As of December 31, 2011, we had long-term debt outstanding of approximately $4.6 billion, including $275.3 million in current maturities, and cash and cash equivalents and short-term investments of $539.5 million. Our ability to service our debt obligations depends in large part upon the level of cash flows generated by our subsidiaries operations, possible dispositions of non-core assets, availability under our unsecured revolving credit facilities and our ability to access the capital markets. As of December 31, 2011, we had $540 million available under revolving credit facilities. We calculate our leverage in relation to capital (i.e., shareholders equity) utilizing two commonly used ratios:

- Gross funded debt to capital, 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, 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 investments.

At December 31, 2011, our gross funded debt to capital ratio was 0.43:1 and our net funded debt to capital ratio was 0.40:1.

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 and our historical ability to access those markets as needed. 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.

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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 where 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 could adversely affect our results of operations

Our operations are subject to many hazards inherent in the drilling, workover and well-servicing and pressure pumping industries, including blowouts, cratering, explosions, fires, loss of well control, loss of or damage to the wellbore or underground reservoir, 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 and natural resources 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. Our operations are also subject to risks of war, civil disturbances or other political events.

Accidents may occur, we may be unable to obtain desired contractual indemnities, and our insurance may prove inadequate in certain cases. 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, insurance may not 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 or self-insured retention. 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.

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

We derive a significant portion of our business from global markets, including major operations in Canada, South America, Mexico, the Middle East, the Far East, the South Pacific, 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 some countries, our operations may be subject to the additional risk of fluctuating currency values and exchange controls. 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 an employment agreement with our Deputy Chairman, President and Chief

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Executive Officer, Anthony G. Petrello, with a term through March 30, 2014. If Mr. Petrello s employment is terminated in the event of death or disability, the Company will make a cash payment of $50 million; or in the event of termination without cause or in the event of a change in control, the Company will make a cash payment based on a formula of three times the average of his base salary and annual bonus paid during the three fiscal years preceding the termination. We do not carry significant amounts of key man insurance. The loss of Mr. Petrello could have an adverse effect on our financial condition or results of operations.

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 removal costs and natural resource, real or personal property and certain economic damages arising from such spills. Some of these laws may impose strict liability for these costs and damages without regard to the conduct of the parties. 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 materials, some of which are classified as solid or hazardous wastes or 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 United States, 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 and natural resource damage and other costs and claims. We are not always successful in allocating all risks of these environmental liabilities to customers, and it is possible that customers who assume the risks will be financially unable to bear any resulting costs.

Under the Comprehensive Environmental Response, Compensation and Liability Act, as amended, 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 environmental laws and regulations may also negatively impact the operations of 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 under the Resources Conservation and Recovery Act, which would make the reclassified wastes subject to more stringent handling, disposal and clean-up requirements. Legislators and regulators in the United States and other jurisdictions where we operate also focus increasingly on restricting the emission of carbon dioxide, methane and other greenhouse gases that may contribute to warming of the Earth s atmosphere, and other climatic changes. The U.S. Congress has considered legislation designed to reduce emission of greenhouse gases, and some states in which we operate have passed legislation or adopted initiatives, such as the Regional Greenhouse Gas Initiative in the northeastern United States and the Western Regional Climate Action Initiative, which establish greenhouse gas inventories and/or cap-and-trade programs. Some international initiatives have also been adopted, such as the United Nations Framework Convention on Climate

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Change s Kyoto Protocol , to which the United States is not a party. In addition, the U.S. Environmental Protection Agency (EPA) has published findings that emissions of greenhouses gases present an endangerment to public health and the environment, paving the way for regulations that would restrict emissions of greenhouse gases under existing provisions of the Clean Air Act.

In October 2009, the EPA enacted rules requiring the reporting of greenhouse gas emissions from large sources and suppliers in the United States. In November 2010, the EPA expanded these rules to include offshore oil and natural gas production and onshore oil and natural gas production, processing, transmission, storage and distribution facilities beginning in 2012 for emissions occurring in 2011. 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, imposes strict liability on responsible parties for removal costs and damages resulting from discharges of oil into U.S. waters. 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.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact the demand for fracturing and other services

Superior performs hydraulic fracturing, a process sometimes used in the completion of oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and, to a lesser extent, oil production. The EPA and certain other federal agencies have announced that they would study the potential adverse impact that fracturing may have on water quality and public health. On August 11, 2011, the U.S. Department of Energy released its report on hydraulic fracturing, recommending the implementation of a variety of measures to reduce the environmental impacts from shale-gas production. These studies could spur initiatives to regulate hydraulic fracturing under the Safe Drinking Water Act or under newly established legislation. Legislation has also been introduced in the U.S. Congress and adopted or introduced in some states that would require the disclosure of chemicals used in the fracturing process. If enacted, the legislation could require fracturing activities to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping requirements and meet plugging and abandonment requirements. Any new laws regulating fracturing activities could cause operational delays or increased costs in exploration and production, which could adversely affect the demand for fracturing services.

Future price declines may result in a writedown of our oil and gas asset carrying values

Our wholly owned oil and gas investment portfolio and our unconsolidated ownership interest in Remora is reflected in assets held for sale. Historically, our proved and unproved properties have been reviewed for impairment of the carrying value based on the successful efforts method of accounting for oil and gas properties; any impairment was expensed in that period. 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.

The estimated fair value of our proved reserves generally declines when there is a significant and sustained decline in oil and natural gas prices. 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 or our ownership interests in unconsolidated affiliates if the estimated fair value of these properties falls below their net book value, which could cause other future writedowns of capitalized costs and asset impairments that could adversely affect our results of operations.

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Significant exercises of stock options could adversely affect the market price of our common shares

As of February 24, 2012, we had 800,000,000 authorized common shares, of which 318,092,267 shares were outstanding. In addition, 39,129,225 common shares were reserved for issuance pursuant to stock option and employee benefit plans. 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 options (and, where applicable, sales pursuant to Rule 144 under the Securities Act), 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

The Board of Directors has the authority to issue a significant number of common shares and up to 25,000,000 preferred shares, as well as 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. In addition, our Board of Directors is divided into three classes, with each class serving a staggered three-year term. Although we have announced plans to declassify the Board, its current structure, 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.

We have an employment agreement with our Deputy Chairman, President and Chief Executive Officer, Anthony G. Petrello. The agreement has a change-in-control provision that could result in a significant cash payment to Mr. 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 audited 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 from Mexico s federal tax authorities in connection with the audit of NDIL s Mexico 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 Mexico branch took similar deductions for depreciation and labor expenses from 2004 to 2008. On June 30, 2009, the government proposed similar assessments against the Mexico 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 2005 through 2008 and against NDIL II for 2007 to 2010. We believe that the potential assessments will range from $6 million to $26 million per year for the period from 2005 to 2009, and in the aggregate, would be approximately $90 million to $95 million. Although we believe that any assessments related to the 2003 and 2005 to 2010 years lack merit, a reserve has been recorded in accordance with accounting principles generally accepted in the United States of America (GAAP). The

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statute of limitations for NDIL s 2004 tax year expired. Accordingly, during the fourth quarter of 2010, we released $7.4 million from our tax reserves, which represented the reserve recorded for that tax year. 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 in excess of 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 the U.S. Congress that could reduce or eliminate the tax benefits associated with our reorganization as a Bermuda company. Legislation enacted by the U.S. 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 U.S. federal income tax purposes. Nabors reorganization was completed on June 24, 2002. There have been and we expect that there may continue to be legislation proposed by the U.S. 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.

The profitability of our operations could be adversely affected by turmoil in the global financial markets

The changes in general financial and political conditions, including the U.S. government budget, the downgrade by Standard & Poor s of the credit rating of U.S. government securities and concerns over the European sovereign debt crisis and banking industry has created a great deal of uncertainty in the recovery of the world economy. If global economic uncertainties continue over a prolonged period of time or develop adversely, there could be a material adverse impact on our credit ratings and liquidity and those of our customers and other worldwide business partners. If global oil and gas prices were to decline rapidly, it could lead our customers to curtail their operations or expansion and cause difficulties for us and our customers to forecast future capital expenditures, which in turn could negatively impact the worldwide rig count and our future financial results.

We do not currently intend to pay dividends on our common shares

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*

Nabors principal executive offices are located in Hamilton, Bermuda. We own or lease executive and administrative office space in Dubai in the United Arab Emirates; Anchorage, Alaska; Calgary, Canada; Indiana, Pennsylvania and Houston, Texas.

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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, which are used to support our operations. 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. The operations of our Oil and Gas operating segment focus on the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids in the United States, the Canada provinces of Alberta and British Columbia, and Colombia.

Our Oil and Gas operating segment includes our wholly owned oil and gas assets and our unconsolidated oil and gas joint ventures. In December 2008, the SEC revised oil and gas reporting disclosures, which clarified that we should consider our equity-method investments when determining whether we have significant oil and gas activities beginning in 2009. A one-year deferral of the disclosure requirements was allowed if an entity became subject to the requirements because of the change to the definition of significant oil and gas activities. When operating results from our wholly owned oil and gas activities were considered with operating results from our unconsolidated oil and gas joint ventures, which we account for under the equity method of accounting, we determined that we had significant oil and gas activities under the new definition at December 31, 2009. Accordingly after the one-year deferral, we began presenting the information with regard to our oil and gas producing activities for the year ended December 31, 2010.

The estimates of net proved oil and gas reserves as of December 31, 2011 were based on reserve reports prepared by independent petroleum engineers. AJM Deloitte prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Canada. Miller and Lents, Ltd. prepared reports of estimated proved oil and gas reserves for both our wholly owned assets and our U.S. joint venture s interests in natural gas and oil properties located in the United States. Cawley, Gillespie & Associates, Inc. prepared reports of estimated proved oil reserves for wholly owned assets located in the Eagle Ford Shale and Giddings field in Grimes County, Texas.

The estimates of net proved oil and gas reserves as of December 31, 2010 were based on reserve reports prepared by the following independent petroleum engineers. AJM Petroleum Consultants prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Canada. Miller and Lents, Ltd. prepared reports of estimated proved oil and gas reserves for both our wholly owned assets and our U.S. joint venture s interests in natural gas and oil properties located in the United States. Netherland, Sewell & Associates, Inc., prepared reports of estimated proved oil reserves for certain properties located in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California. Lonquist & Co., LLC prepared reports of estimated proved oil and gas reserves for our wholly owned assets in Colombia.

Summary of Oil and Gas Reserves

The table below summarizes the proved reserves in each geographic area and by product type for our wholly owned subsidiaries and our proportionate interests in our equity companies. We report proved reserves on the basis of the average of the first-day-of-the-month price for each month during the last 12-month period. Estimates of volumes of proved reserves of natural gas at year end are expressed in billions of cubic feet of natural gas (Bcf) at a pressure base of 14.73 pounds per square inch for natural gas and in millions of barrels (MMBbls) for oil and natural gas liquids.

For our wholly owned properties in the United States and the properties of our unconsolidated U.S. joint venture, the prices used in the reserve reports were $4.12 per thousand cubic feet of natural gas (Mcf) for the 12-month average of natural gas, $57.71 per barrel for natural gas liquids and $96.19 per barrel for oil at December 31, 2011. For our wholly owned properties in Canada, the price used in our reserve reports was $3.85 per mcf for the 12-month average of natural gas at December 31, 2011.

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No major discovery or other favorable or adverse event has occurred since December 31, 2011, that would cause a significant change in the estimated proved reserves as of that date.

	Reserves	
Reserve category	**Liquids (MMBbls)**	**Natural Gas (Bcf)**
As of December 31, 2011:		
Proved		
Developed		
Consolidated Subsidiaries		
United States	.9(2)	13.6
Canada		8.2
Colombia		
Total Consolidated	.9	21.8
Equity Companies(1)		
United States	6.3	256.4(3)
Canada		(4)
Colombia	(5)	
Total Equity Companies	6.3	256.4
Total Developed	7.2	278.2
Undeveloped		
Consolidated Subsidiaries		
United States	.9	3.3
Canada		
Colombia		
Total Consolidated	.9	3.3
Equity Companies(1)		
United States	9.6	326.1
Canada		
Colombia		
Total Equity Companies	9.6	326.1
Total Undeveloped	10.5	329.4
Total Proved	17.7	607.6
As of December 31, 2010:		
Proved		
Developed		
Consolidated Subsidiaries		
United States	2.7(2)	17.1
Canada		5.5
Colombia	1.6	
Total Consolidated	4.3	22.6
Equity Companies(1)		
United States	3.0	147.1
Canada		5.2
Colombia	0.5	
Total Equity Companies	3.5	152.3

Total Developed	7.8	174.9
Undeveloped		
Consolidated Subsidiaries		
United States	18.5	2.7
Canada		
Colombia	0.4	
Total Consolidated	18.9	2.7
Equity Companies(1)		
United States	4.9	405.7
Canada		
Colombia	1.4	
Total Equity Companies	6.3	405.7
Total Undeveloped	25.2	408.4
Total Proved	33.0	583.3

(1) Represents our proportionate interests in our equity companies.

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(2) On December 14, 2011, we sold our 25% working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California. We received approximately $71.6 million in cash from the sale. During 2010, we purchased our 25% working interest and at December 31, 2010, proved reserves in Cat Canyon were estimated at 20.8 MMBbls.

(3) Relates to acquisitions of properties with 360.4 Bcfe and drilling of non-proved properties of 122.2 Bcfe. In addition, negative revisions of 384 Bcfe were noted primarily resulting from proved undeveloped reserves being reclassified to non-proved status in accordance with the SEC five-year guidance for recording proved reserves.

(4) Relates to SMVP that was dissolved in June 2011, and of proved reserves of 4.8 Bcfe that was exchanged for our ownership interest.

(5) Relates to the sale of Remora s assets which resulted in a decrease in proved reserves of 9.5 Bcfe.

In the preceding reserve information, consolidated subsidiary and our proportionate interests in our equity company reserves are reported separately. However, we operate our business with the same view of equity company reserves as for reserves from consolidated subsidiaries.

The estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process based on rigorous technical evaluations, commercial and market assessments and detailed analysis of well information such as flow rates and reservoir pressure declines. Furthermore, we record proved reserves only for projects that have received significant funding commitments by management made toward the development of the reserves. Although we are reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in projections of long-term oil and natural gas price levels.

Technologies Used in Establishing Proved Reserves Additions in 2011

Proved reserves were based on estimates generated through the integration of available and appropriate data, utilizing well established technologies that have been demonstrated in the field to yield repeatable and consistent results.

Data used in these integrated assessments included information obtained directly from the subsurface via wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements including high-quality 2-D and 3-D seismic data, calibrated with available well control. Where applicable, surface geological information was also utilized. The tools used to interpret the data included proprietary seismic processing software, proprietary reservoir modeling and simulation software and commercially available data analysis packages.

In some circumstances, where appropriate analog reservoirs were available, reservoir parameters from these analogs were used to increase the quality of and confidence in the reserves estimates.

Internal Controls over Proved Reserves

Our Oil and Gas operating segment is managed by and staffed with individuals who have an average of more than 20 years of technical experience in the petroleum industry. We maintain computerized records of our reserve estimates and production data. Appropriate controls, including limitations on access and updating capabilities, are in place to ensure data integrity. We engage qualified third-party reservoir engineers and perform reviews to ensure reserve estimations include all properties owned and are based on correct working and net revenue interests. Key components of the reserve estimation process include technical evaluations and analysis of

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well and field performance and a rigorous peer review. No changes may be made to reserve estimates unless these changes have been thoroughly reviewed and evaluated by authorized personnel at Nabors. After all changes are made, senior management reviews the estimates for final endorsement.

Proved Undeveloped Reserves

At December 31, 2011, approximately 392 billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or natural gas liquids, (Bcfe) of our proved reserves were classified as proved undeveloped, which represented 55% of the 714 Bcfe reported in proved reserves. This amount is inclusive of both consolidated subsidiaries and equity company reserves. At December 31, 2011, our wholly owned reserves are reported as assets held for sale. Our unconsolidated U.S. joint venture only adds PUDs that will be developed within a five-year time horizon. Progress was made in converting proved undeveloped reserves into proved developed reserves in 2011. During 2011, we completed development work that resulted in the transfer of approximately 63.047 Bcfe from proved undeveloped to proved developed reserves. We spent approximately $.4 million and our unconsolidated U.S. joint venture provided approximately $89 million associated with the development of PUDs in 2011.

Oil and Gas Production, Production Prices and Production Costs

Oil and Gas Production

The table below summarizes production by final product sold, average production sales price and average production cost, each by geographic area for the years ended December 31, 2011 and 2010. Production costs are costs to operate and maintain our wells and related equipment and include the cost of labor, well-service and repair, location maintenance, power and fuel, transportation, cost of product, property taxes and production-related general and administrative costs.

	United States		Canada		Colombia		Total	
	Liquids (MMBbls)	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**	**Liquids (MMBbls)**	**Natural Gas (Bcf)**
As of December 31, 2011:								
Oil and natural gas liquids production								
Consolidated Subsidiaries	.140	2.944		2.117	.111	.011	.251	5.072
Equity Companies(1)	.409	18.634		.380	.316		.725	19.014
Average production sales prices:								
Consolidated Subsidiaries	$ 88.94	$ 4.09	$	$ 3.33	$ 111.57	$ 5.00	$ 98.91	$ 3.77
Equity Companies(1)	$ 58.16	$ 4.03	$	$ 3.48	$ 84.47	$	$ 69.63	$ 4.02
Average production costs ($/bce):								
Consolidated Subsidiaries		$ 3.35/Mcfe(2)		$ 12.96/Mcfe	$ 32.98/Boe(2)			
Equity Companies(1)		$ 1.32/Mcfe		$ 11.99/Mcfe	$ 33.49/Boe			
As of December 31, 2010:								
Oil and natural gas liquids production								
Consolidated Subsidiaries	.073	3.533		3.058	.230		.303	6.591
Equity Companies(1)	.249	12.338		1.535	.273		.522	13.873
Average production sales prices:								
Consolidated Subsidiaries	$ 63.77	$ 4.19	$	$ 3.69	$ 72.25	$	$ 70.19	$ 2.71
Equity Companies(1)	$ 74.86	$ 4.43	$	$ 3.93	$ 73.90	$	$ 58.59	$ 4.11
Average production costs ($/bce):								
Consolidated Subsidiaries		$ 2.14/Mcfe		$ 2.60/Mcfe	$ 34.42Bboe			
Equity Companies(1)		$ 1.33/Mcfe		$ 5.89/Mcfe	$ 33.60/Boe			

(1) Represents our proportionate interests in our equity companies.

(2) Reflects the thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one barrel of crude oil or natural gas liquids, or as Mcfe and reflects the barrel of oil equivalent or as Boe .

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Drilling and Other Exploratory and Development Activities

During 2011 and 2010, our drilling program focused on proven and emerging oil and natural gas basins in the United States. Our drilling program includes development activities with properties located in the United States, Canada and Colombia that are being actively marketed. The following tables provide the number of oil and gas wells completed during 2011 and 2010.

Number of Net Productive and Exploratory Wells Drilled

	Net Productive Exploratory Wells Drilled	Net Dry Exploratory Wells Drilled
For the year ended December 31, 2011:		
Consolidated Subsidiaries		
United States	5.14	3.63
Canada	3.00	4.00
Colombia		
Total Consolidated	8.14	7.63
Equity Companies(1)		
United States		
Canada		
Colombia		
Total Equity Companies		
For the year ended December 31, 2010:		
Consolidated Subsidiaries		
United States	1.9	
Canada		
Colombia	4.2	
Total Consolidated	6.1	
Equity Companies(1)		
United States	0.9	
Canada		
Colombia	3.3	2.1
Total Equity Companies	4.2	2.1

(1) Represents our proportionate interests in our equity companies.

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	Net Productive Development Wells Drilled	Net Dry Development Wells Drilled
For the year ended December 31, 2011:		
Consolidated Subsidiaries		
United States	2.04	3.28
Canada		
Colombia	2.00	1.40
Total Consolidated	4.04	4.68
Equity Companies(1)		
United States	10.45	
Canada		
Colombia		
Total Equity Companies	10.45	
For the year ended December 31, 2010:		
Consolidated Subsidiaries		
United States	1.2	0.1
Canada		
Colombia		
Total Consolidated	1.2	0.1
Equity Companies(1)		
United States	9.5	
Canada		
Colombia	1.6	
Total Equity Companies	11.1	

(1) Represents our proportionate interests in our equity companies.

Present Activities

The following table provides the number of wells in the process of drilling as of December 31, 2011.

Wells Drilling

	United States		Canada		Colombia		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Consolidated Subsidiaries	13.00	4.11					13.00	4.11
Equity Companies(1)	10.45	10.45					10.45	10.45

(1) Represents our proportionate interests in our equity companies.

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Oil and Gas Properties, Wells, Operations and Acreage

Gross and Net Productive Wells

	For the year ended December 31, 2011	
	Gross	Net
Consolidated Subsidiaries		
United States	419.0	48.9
Canada	7.0	7.0
Colombia	3.0	1.5
Total Consolidated	429.0	57.4
Equity Companies(1)		
United States	537.1	408.7
Canada		
Colombia		
Total Equity Companies	537.1	408.7

(1) Represents our proportionate interests in our equity companies.

Gross and Net Developed Acreage

	December 31, 2011							
	United States		Canada		Colombia		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Consolidated Subsidiaries	201,414	26,577	5,197	4,877			206,611	31,454
Equity Companies(1)	225,743	123,896					225,743	124,394

(1) Represents our proportionate interests in our equity companies.

Gross and Net Undeveloped Acreage

	December 31, 2011							
	United States		Canada		Colombia		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Consolidated Subsidiaries	586,701	202,187	50,673	44,402	581,450	280,946	1,218,824	527,535
Equity Companies(1)	368,767	189,002					368,767	189,002

(1) Represents our proportionate interests in our equity companies.

Lease Expirations of Net Acreage

	United States			Canada			Colombia		
	2012	2013	2014	2012	2013	2014	2012	2013	2014
Consolidated Subsidiaries(2)	36,327	16,811	11,749	12,517					
Equity Companies(1)(3)	33,916	57,251	26,036						

(1) Represents our proportionate interests in our equity companies.

(2) The carrying value of leases at December 31, 2011 was approximately $105.8 million.

(3) The carrying value of our proportionate share of leases at December 31, 2011 was approximately $103.7 million.

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Although our drilling program includes development activities with properties that are being actively marketed, we plan to continue the terms of some of these licenses and concession areas through operational or administrative actions. We believe the amount of undeveloped acreage that will be abandoned or lease allowed to expire at the end of the lease term is immaterial to our operations.

Additional information about our properties can be found in Notes 2 Summary of Significant Accounting Policies, 9 Property, Plant and Equipment (each, under the caption Property, Plant and Equipment), 18 Commitments and Contingencies (under the caption Operating Leases), and 24 Supplemental Information on Oil and Gas Exploration and Production Activities 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, 2011, 2010 and 2009, can be found in Note 22 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. For matters where an unfavorable outcome is reasonably possible and significant, we disclose the nature of the matter and a range of potential exposure, unless an estimate cannot be made at the time of disclosure. 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 our vendors and compliance with the Foreign Corrupt Practices Act. The inquiry relates to transactions with and involving Panalpina, which provided freight forwarding and customs clearance services to some of our affiliates. 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, 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 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 our 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. In November 2011, we received a notice from the Algeria Supreme Court that a decision is expected in March 2012. If we are 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.

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In March 2011, the Court of Ouargla (in Algeria), sitting at first instance, entered a judgment of approximately $39.1 million against NDIL relating to alleged violations of Algeria s foreign currency exchange controls, which require that goods and services provided locally be invoiced and paid in local currency. The case relates to certain foreign currency payments made to NDIL by CEPSA, a Spanish operator, for wells drilled in 2006. Approximately $7.5 million of the total contract amount was paid offshore in foreign currency, and approximately $3.2 million was paid in local currency. The judgment includes fines and penalties of approximately four times the amount at issue, and is not payable pending appeal. We have appealed the ruling based on our understanding that the law in question applies only to resident entities incorporated under Algerian law. An intermediate court of appeals has upheld the lower court s ruling, and we have appealed the matter to the Algeria Supreme Court. While our payments were consistent with our historical operations in the country, and, we believe, those of other multinational corporations there, and interpretations of the law by the Central Bank of Algeria, the ultimate resolution of this matter could result in a loss of up to $31.1 million in excess of amounts accrued.

On September 21, 2011, we received an informal inquiry from the SEC related to perquisites and personal benefits received by the officers and directors of Nabors, including their use of non-commercial aircraft. Our Audit Committee and Board of Directors have been apprised of this inquiry and we are cooperating with the SEC. The ultimate outcome of this process cannot be determined at this time.

Nabors Industries Ltd. and its Board of Directors have been sued by purported shareholders in three separate shareholder s derivative lawsuits filed in federal and state court in Houston, Texas. The cases were filed on November 18, 2011, January 9, 2012, and November 30, 2011, and are pending, respectively, before Judges Ewing Werlein and Gray Miller in the United States Southern District of Texas, Houston Division, and Judge Mike Miller of the 11th Judicial District Court of Harris County, Texas. The case filed on January 9, 2012 was voluntarily dismissed on January 31, 2012. The other cases remain pending. The allegations of each lawsuit were substantially similar, alleging that the members of the Board breached their fiduciary duties to the Company, wasted corporate assets, and committed oppressive conduct against the shareholders by agreeing to and/or acquiescing in certain compensation arrangements with two senior officers of the Company, Eugene M. Isenberg and Anthony G. Petrello. The remaining lawsuits seek relief that includes an award of monetary damages in an unspecified amount, disgorgement by Messrs. Isenberg and Petrello of allegedly excessive compensation in an unspecified amount of at least $90 million, and equitable relief to reform Nabors compensation practices. The ultimate outcome of these lawsuits cannot be determined at this time.

ITEM 4. ***MINE SAFETY DISCLOSURES***

Not applicable.

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PART II

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

STOCK PERFORMANCE GRAPH

The following graph illustrates comparisons of five-year cumulative total returns among Nabors, the S&P 500 Index and the Dow Jones Oil Equipment and Services Index. Total return assumes $100 invested on December 31, 2006 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, 2007 2011.

	2007	2008	2009	2010	2011
Nabors Industries Ltd.	**92**	**40**	**74**	**79**	**58**
S&P 500 Index	105	66	84	97	99
Dow Jones Oil Equipment and Services Index	145	59	97	124	109

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Market and Share Prices

Our common shares are traded on the New York Stock Exchange under the symbol NBR . At February 24, 2012, there were approximately 1,427 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.

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
2010		
First quarter	27.05	18.74
Second quarter	22.82	16.90
Third quarter	19.13	15.54
Fourth quarter	23.93	17.36
2011		
First quarter	30.70	21.50
Second quarter	32.47	22.43
Third quarter	27.63	12.26
Fourth quarter	20.69	11.05

The following table provides information relating to Nabors repurchase of common shares during the three months ended December 31, 2011:

Period	Total Number of Shares Purchased(1)	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)
		(In thousands, except per share amounts)		
October 1 October 31				
November 1 November 30	<1	$ 18.69		
December 1 December 31	420	$ 18.24		

(1) Shares were withheld from employees and directors 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. The 2003 Employee Stock Plan, 1998 Employee Stock Plan, 1999 Stock Option Plan for Non-employee Directors 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) We do not intend to make further purchases of our common shares under a share repurchase program that was authorized by the Board of Directors in July 2006.

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

Dividend Policy

See Part I, Item 1A. Risk Factors *We do not currently intend to pay dividends on our common shares* and Part II, Item 5. I. Market and Share Prices.

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Shareholder Matters

Bermuda has exchange controls which apply to residents in respect of the Bermuda dollar. As an exempted 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).

ITEM 6. *SELECTED FINANCIAL DATA*

	Year Ended December 31,				
Operating Data(1)(2)	**2011**	**2010**	**2009**	**2008**	**2007**
	(In thousands, except per share amounts and ratio data)				
Revenues and other income:					
Operating revenues	$ 6,060,351	$ 4,134,483	$ 3,662,220	$ 5,394,225	$ 4,755,957
Earnings (losses) from unconsolidated affiliates	56,647	33,267	(155,432)	(192,548)	20,980
Investment income (loss)	19,940	7,263	25,522	21,383	(16,301)
Total revenues and other income	6,136,938	4,175,013	3,532,310	5,223,060	4,760,636
Costs and other deductions:					
Direct costs	3,775,964	2,400,519	1,981,504	3,063,257	2,720,898
General and administrative expenses	489,892	338,720	421,492	473,885	429,994
Depreciation and amortization	924,094	760,962	663,958	609,155	463,985
Interest expense	256,633	272,712	266,047	196,726	154,934
Losses (gains) on sales and retirements of long-lived assets and other expense (income), net	4,514	47,238	11,982	15,143	11,614
Impairments and other charges	198,072	61,292	118,543	145,447	
Total costs and other deductions	5,649,169	3,881,443	3,463,526	4,503,613	3,781,425
Income (loss) from continuing operations before income taxes	487,769	293,570	68,784	719,447	979,211
Income tax expense (benefit)	142,605	36,950	(63,937)	200,186	178,655
Subsidiary preferred stock dividend	3,000	750			
Income (loss) from continuing operations, net of tax	342,164	255,870	132,721	519,261	800,556
Income (loss) from discontinued operations, net of tax	(97,440)	(161,090)	(218,609)	(39,597)	64,726
Net income (loss)	244,724	94,780	(85,888)	479,664	865,282
Less: Net (income) loss attributable to noncontrolling interest	(1,045)	(85)	342	(3,927)	420
Net income (loss) attributable to Nabors	$ 243,679	$ 94,695	$ (85,546)	$ 475,737	$ 865,702
Earnings (losses) per share:					
Basic from continuing operations	$ 1.19	$ .90	$ .47	$ 1.83	$ 2.85
Basic from discontinued operations	(.34)	(.57)	(.77)	(.14)	.23
Total Basic	$ .85	$ .33	$ (.30)	$ 1.69	$ 3.08

Diluted from continuing operations	$ 1.17	$ .88	$ .46	$ 1.79	$ 2.78
Diluted from discontinued operations	(.34)	(.55)	(.76)	(.14)	.22
Total Diluted	$ .83	$ .33	$ (.30)	$ 1.65	$ 3.00
Weighted-average number of common shares outstanding:					
Basic	287,118	285,145	283,326	281,622	281,238
Diluted	292,484	289,996	286,502	288,236	288,226
Capital expenditures and acquisitions of businesses(3)	$ 2,247,735	$ 1,878,063	$ 990,287	$ 1,578,241	$ 1,945,932
Interest coverage ratio(4)	8.1:1	7.0:1	7.4:1	22.6:1	37.3:1

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Balance Sheet Data(1)(2)	2011	2010	As of December 31, 2009	2008	2007
			(In thousands, except ratio data)		
Cash, cash equivalents and short-term investments(5)	$ 539,489	$ 801,190	$ 1,090,851	$ 586,111	$ 820,105
Working capital	1,285,752	458,550	1,568,042	1,037,734	719,674
Property, plant and equipment, net	8,629,946	7,815,419	7,646,050	7,331,959	6,669,013
Total assets	12,912,140	11,646,569	10,644,690	10,517,899	10,139,783
Long-term debt	4,348,490	3,064,126	3,940,605	3,600,533	2,894,659
Shareholders equity	5,587,815	5,328,162	5,167,656	4,904,106	4,801,579
Funded debt to capital ratio:					
Gross(6)	0.43:1	0.42:1	0.41:1	0.41:1	0.39:1
Net(7)	0.40:1	0.38:1	0.33:1	0.37:1	0.33:1

(1) All periods present the operating activities of our wholly owned oil and gas assets in the United States, Canada and Colombia, including equity interests in Canada and Colombia, as well as the Nabors Blue Sky Ltd. and Sea Mar businesses as discontinued operations.

(2) Our acquisitions results of operations and financial position have been included beginning on the respective dates of acquisition and include Peak (July 2011), SMVP (June 2011), Energy Contractors (December 2010) and Superior (September 2010).

(3) Represents capital expenditures and the total purchase price of acquisitions.

(4) The interest coverage ratio is a trailing 12-month quotient of the sum of (x) income (loss) from continuing operations, net of tax, net income (loss) attributable to noncontrolling interest, interest expense, subsidiary preferred stock dividends, depreciation and amortization, impairments and other charges, income tax expense (benefit) and our proportionate share of writedowns from our unconsolidated oil and gas joint venture *less* investment income (loss) *divided* by (y) the sum of cash interest expense and subsidiary preferred stock dividends. 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.

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

(6) 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.

(7) 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 investments. 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.

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

Management Overview

This section 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.

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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 and gas markets in the world. Our worldwide fleet of actively marketed rigs consists of 499 land drilling rigs, 755 rigs for land well-servicing and workover work in the United States and Canada, offshore platform rigs, jackup units, barge rigs and a large component of trucks and fluid hauling vehicles. We have invested in oil and gas exploration, development and production activities in the United States, Canada and Colombia, but have announced our intention to dispose of a significant portion of our oil and gas portfolio in an expeditious and prudent manner.

The majority of our business is conducted through our various Contract Drilling operating segments, which include our drilling, well-servicing and workover operations, on land and offshore. Our hydraulic fracturing and downhole surveying services are included in our Pressure Pumping operating segment. Our oil and gas exploration, development and production operations are included in our Oil and Gas operating segment, or in discontinued operations in some cases. Our operating segments engaged in drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction 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. Our customers spending is determined principally by their internally generated cash flow and to a lesser extent by joint venture arrangements and funding from the capital markets. In our U.S. Lower 48 Land Drilling, Canadian Drilling and Pressure Pumping business units, operations have traditionally been driven by natural gas prices but the majority of current activity is being driven by the price of oil and natural gas liquids from unconventional reservoirs (shales). In our Alaskan, International, U.S. Offshore (Gulf of Mexico), Canadian Well-servicing and U.S. Land Well-servicing business units, operations are driven by oil prices. The following table sets forth natural gas and oil price data per Bloomberg for the last three years:

	Year Ended December 31,			Increase / (Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
Commodity prices:							
Average Henry Hub natural gas spot price ($/thousand cubic feet (mcf))	$ 4.00	$ 4.37	$ 3.94	$ (.37)	(8)%	$ .43	11%
Average West Texas intermediate crude oil spot price ($/barrel)	$ 95.05	$ 79.51	$ 61.99	$ 15.54	20%	$ 17.52	28%

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 and into the first half of 2010 resulted in sustained lower natural gas and oil prices, which led to a sharp decline in the demand for drilling and workover services. During the latter half of 2010 and throughout 2011, commodity prices strengthened and demand for drilling activity improved. Continued fluctuations in the demand for natural 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, 2011 totaled $6.1 billion, representing an increase of $1.9 billion, or 47% as compared to the year ended December 31, 2010. Adjusted income derived from operating activities and net income (loss) from continuing operations for the year ended December 31, 2011 totaled $927.0 million and $342.2 million ($1.17 per diluted share), respectively, representing increases of 39% and 34%, respectively, compared to the year ended December 31, 2010.

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Operating revenues and Earnings (losses) from unconsolidated affiliates for the year ended December 31, 2010 totaled $4.2 billion, representing an increase of $661.0 million, or 19% as compared to the year ended December 31, 2009. Adjusted income derived from operating activities and net income (loss) from continuing operations for the year ended December 31, 2010 totaled $667.5 million and $255.9 million ($.88 per diluted share), respectively, representing increases of 52% and 93%, respectively, compared to the year ended December 31, 2009.

During 2011, operating results improved as compared to 2010 primarily due to the incremental revenue and positive operating results from the addition of our Pressure Pumping operating segment beginning in September 2010, increased drilling activity in oil- and liquids-rich shale plays in our drilling operations in both our U.S. Lower 48 Land and Canada Drilling business units and increased well-servicing activity in the U.S. and Canada. However, our operating results and activity levels continued to be negatively impacted in our U.S. Offshore operations in response to uncertainty in the regulatory environment in the Gulf of Mexico; our Alaskan operations due to key customers spending constraints; and in Saudi Arabia due to downtime and reduced rates on several jackup rigs.

Our net income from continuing operations during 2011 was negatively impacted by $198.1 million in impairments and other charges, $100 million of which related to a provision for a contingent liability that existed on December 31, 2011 for a potential termination payment to our former Chief Executive Officer. See Note 3 for further discussion and subsequent developments. The remaining $98.1 million was comprised of a provision for retirement of long-lived assets recorded by multiple operating segments. This related to the decommissioning and retirement of assets previously utilized in our U.S. Lower 48 Land Drilling, International and U.S. Well-servicing operations and the amounts are reflected in the Impairments and other charges line in our consolidated statements of income (loss).

During 2010, operating results improved over 2009 primarily due to the incremental revenue and positive operating results from our Pressure Pumping operating segment and increased drilling activity in 2010 in our U.S. Lower 48 Land Drilling and Canada Well-servicing operations relating to increased drilling activity in oil and the liquids-oil shale plays. Our U.S. Well-servicing business also improved with continuing strong crude oil prices, which led to increased activity. However, our operating results and activity levels were negatively impacted in our U.S. Offshore, Alaska and International operations.

Our U.S. Offshore operations were improving during the first half of 2010 until the Gulf of Mexico explosion and oil spill occurred mid-year, which resulted in temporary suspension of offshore drilling and further delays in our customers ability to obtain permits, which limited the use of our assets. Specifically, operating results were impacted because our customers suspended most of their operations in the Gulf of Mexico, largely as a result of their inability to obtain government permits. Our Alaska operating segment was negatively impacted because the largest operator in the area curtailed and suspended drilling operations, creating a surplus of rigs in the market and causing price competition. Our International results were flat as the increase of land rig activity was essentially offset by contract renewals on our jackup rigs at significantly lower average dayrates.

Our net income from continuing operations during 2010 was negatively impacted by impairments and other charges of $61.3 million. We recognized goodwill impairment and recorded provisions for retirement of long-lived assets of approximately $10.7 million and $27.4 million, respectively, to assets in our U.S. Offshore operating segment, primarily driven by current market conditions in the Gulf of Mexico. Additionally, we recorded impairments of $23.2 million relating to asset retirements across our U.S. Lower 48 Land, U.S. Well-servicing and U.S. Offshore Contract Drilling segments. Discontinued operations include impairments of $54.3 million relating to an oil and gas financing receivable and $137.8 million under application of the successful-efforts method of accounting for our wholly owned oil and gas-related assets.

Our net income from continuing operations during 2009 was negatively impacted by impairments and other charges of $118.5 million. The impairments and other charges included recognition of other-than-temporary impairments of $54.3 million relating to our available-for-sale securities, and a provision for retirement totaling

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$64.2 million to long-lived assets from our U.S. Offshore, Alaska, Canada and International contract drilling segments.

During 2011, we sold some of our wholly owned oil and gas assets in Colombia and received proceeds of $89.2 million. Additionally, Remora completed sales of its oil and gas assets in Colombia for gross proceeds of $333.1 million and has made cash distributions to us totaling $143.0 million during 2011 with a final distribution expected upon dissolution of the joint venture. We sold our working interest in properties located in California and received proceeds of $71.6 million. Our discontinued operations also include impairments of $255.0 million relating to oil and gas-centered assets and $7.9 million relating to carrying value aircraft and other drilling equipment.

We expect our operating results for 2012 to increase from levels realized during 2011, driven by the anticipated sustained higher oil prices and the related impact on drilling and well-servicing activity and dayrates, along with the contributions from our Pressure Pumping operating segment. The key factors supporting our projections are:

- An increase in drilling in oil- and liquids-rich areas incremental to traditional dry gas regions by our U.S. Lower 48 Land and Canada Drilling and Well-servicing operations;

- The extent of current term contracts in both our Lower 48 rig and pressure-pumping segments, combined with new deployments in 2012, should serve to mitigate the impact of a potentially more rapid reduction in gas drilling activity arising from weaker natural gas pricing;

- Our expectation of a continued increase from ancillary well-site services, primarily technical pumping services and down-hole surveying services, resulting from our Pressure Pumping operating segment; and

- The anticipated positive impact on our overall level of drilling and well-servicing activity and margins resulting from our new and upgraded rigs and equipment added to our fleet over the past five years, which we expect will enhance our competitive position as 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)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages and rig activity)						
Reportable segments:							
Operating revenues and Earnings (losses) from unconsolidated affiliates from continuing operations:(1)							
Contract Drilling:(2)							
U.S. Lower 48 Land Drilling	$ 1,698,620	$ 1,294,853	$ 1,082,531	$ 403,767	31%	$ 212,322	20%
U.S. Land Well-servicing	701,223	444,665	412,243	256,558	58%	32,422	8%
U.S. Offshore	170,727	123,761	157,305	46,966	38%	(33,544)	(21)%
Alaska	129,894	179,218	204,407	(49,324)	(28)%	(25,189)	(12)%
Canada	574,754	389,229	298,653	185,525	48%	90,576	30%
International	1,104,461	1,093,608	1,265,097	10,853	1%	(171,489)	(14)%
Subtotal Contract Drilling(3)	4,379,679	3,525,334	3,420,236	854,345	24%	105,098	3%
Pressure Pumping(4)	1,237,306	321,295		916,011	285%	321,295	100%
Oil and Gas(5)(6)	59,685	18,657	(182,654)	41,028	220%	201,311	110%
Other Operating Segments(7)(8)	674,206	427,154	417,531	247,052	58%	9,623	2%

Other reconciling items(9)	(233,878)	(124,690)	(148,325)	(109,188)	(88)%	23,635	16%
Total	$ 6,116,998	$ 4,167,750	$ 3,506,788	$ 1,949,248	47%	$ 660,962	19%

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	Year Ended December 31, 2011	2010	2009	Increase/(Decrease) 2011 to 2010		2010 to 2009	
	(In thousands, except percentages and rig activity)						
Adjusted income (loss) derived from operating activities from continuing operations:(1)(10)							
Contract Drilling:							
U.S. Lower 48 Land Drilling	$ 414,317	$ 274,215	$ 294,679	$ 140,102	51%	$ (20,464)	(7)%
U.S. Land Well-servicing	74,725	31,597	28,950	43,128	136%	2,647	9%
U.S. Offshore	843	9,245	30,508	(8,402)	(91)%	(21,263)	(70)%
Alaska	27,671	51,896	62,742	(24,225)	(47)%	(10,846)	(17)%
Canada	94,637	22,970	(7,019)	71,667	312%	29,989	427%
International	123,813	254,744	365,566	(130,931)	(51)%	(110,822)	(30)%
Subtotal Contract Drilling(3)	736,006	644,667	775,426	91,339	14%	(130,759)	(17)%
Pressure Pumping(4)	229,125	66,651		162,474	244%	66,651	100%
Oil and Gas(5)(6)	59,685	18,657	(182,654)	41,028	220%	201,311	110%
Other Operating Segments(8)(9)	55,617	42,401	35,319	13,216	31%	7,082	20%
Other reconciling items(11)	(153,385)	(104,827)	(188,257)	(48,558)	(46)%	83,430	44%
Total	$ 927,048	$ 667,549	$ 439,834	$ 259,499	39%	$ 227,715	52%
Interest expense	(256,633)	(272,712)	(266,047)	16,079	6%	(6,665)	(3)%
Investment income (loss)	19,940	7,263	25,522	12,677	175%	(18,259)	(72)%
Gains (losses) on sales and retirements of long-lived assets and other income (expense), net	(4,514)	(47,238)	(11,982)	42,724	90%	(35,256)	(294)%
Impairments and other charges(12)	(198,072)	(61,292)	(118,543)	(136,780)	(223)%	57,251	48%
Income (loss) from continuing operations before income taxes	487,769	293,570	68,784	194,199	66%	224,786	327%
Income tax expense (benefit)	142,605	36,950	(63,937)	105,655	286%	100,887	158%
Subsidiary preferred stock dividend	3,000	750		2,250	300%	750	100%
Income (loss) from continuing operations, net of tax	342,164	255,870	132,721	86,294	34%	123,149	93%
Income (loss) from discontinued operations, net of tax	(97,440)	(161,090)	(218,609)	63,650	40%	57,519	26%
Net income (loss)	244,724	94,780	(85,888)	149,944	158%	180,668	210%
Less: Net (income) loss attributable to noncontrolling interest	(1,045)	(85)	342	(960)	n/m(16)	(427)	(125)%
Net income (loss) attributable to Nabors	$ 243,679	$ 94,695	$ (85,546)	$ 148,984	157%	$ 180,241	211%
Rig activity:							
Rig years:(13)							
U.S. Lower 48 Land Drilling	200.2	174.5	149.4	25.7	15%	25.1	17%
U.S. Offshore	9.6	9.4	11.0	0.2	2%	(1.6)	(15)%
Alaska	4.9	7.4	10.0	(2.5)	(34)%	(2.6)	(26)%
Canada	39.8	29.8	19.7	10.0	34%	10.1	51%
International(14)	105.3	97.8	100.2	7.5	8%	(2.4)	(2)%
Total rig years	359.8	318.9	290.3	40.9	13%	28.6	10%

Rig hours:(15)							
U.S. Land Well-servicing	791,956	643,813	590,878	148,143	23%	52,935	9%
Canada Well-servicing	184,908	172,589	143,824	12,319	7%	28,765	20%
Total rig hours	976,864	816,402	734,702	160,462	20%	81,700	11%

(1) All periods present the operating activities of our wholly owned oil and gas assets in the United States, Canada and Colombia, including equity interests in Canada and Colombia, as well as the Nabors Blue Sky Ltd. business as discontinued operations.

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

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(3) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $(1.2) million, $6.9 million and $9.7 million for the years ended December 31, 2011, 2010 and 2009, respectively.

(4) Includes operating results of the Superior acquisition beginning September 10, 2010.

(5) Represents our oil and gas exploration, development and production operations. Includes our proportionate share of full-cost ceiling test writedowns recorded by our unconsolidated U.S. oil and gas joint venture of $(15.6) million and $(189.3) million for the years ended December 31, 2011 and 2009, respectively.

(6) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $59.7 million, $18.7 million and $(182.6) million for the years ended December 31, 2011, 2010 and 2009, respectively. Additional information is provided in Note 24 Supplemental Information on Oil and Gas Exploration and Production Activities in Part II, Item 8. Financial Statements and Supplementary Data.

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

(8) Includes earnings (losses), net from unconsolidated affiliates, accounted for using the equity method, of $(1.9) million, $7.7 million and $17.5 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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

(10) 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. These amounts should not be used as a substitute for those amounts reported in accordance with 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 accurately reflect our ongoing profitability. A reconciliation of this non-GAAP measure to income (loss) from continuing operations before income taxes, which is a GAAP measure, is provided in the above table.

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

(12) Represents impairments and other charges recorded during the years ended December 31, 2011, 2010 and 2009, respectively.

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

(14) International rig years include our equivalent percentage ownership of rigs owned by unconsolidated affiliates, which totaled 2.1 years, 2.2 years and 2.5 years during the years ended December 31, 2011, 2010 and 2009, respectively.

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

(16) The percentage is so large that it 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 and pressure pumping, on land and offshore.

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

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages and rig activity)						
Operating revenues	$ 1,698,620	$ 1,294,853	$ 1,082,531	$ 403,767	31%	$ 212,322	20%
Adjusted income derived from operating activities	$ 414,317	$ 274,215	$ 294,679	$ 140,102	51%	$ (20,464)	(7)%
Rig years	200.2	174.5	149.4	25.7	15%	25.1	17%

Operating results increased from 2010 to 2011 primarily due to higher average dayrates and increases in drilling activity, driven by deployment of rigs into oil- and liquids-rich shale areas. The increase was partially offset by higher operating costs associated with increased drilling activity, as well as higher depreciation expense related to new rigs placed into service since January 2010.

Operating revenues increased from 2009 to 2010 primarily due to higher average dayrates and utilization. The increase was partially offset by the decrease in early contract termination revenue. Operating revenues related to early contract termination during 2010 were $23.2 million as compared to $108.5 million in 2009.

Adjusted income derived from operating activities decreased from 2009 to 2010 due to an increase in operating costs associated with the increased drilling activity. Operating results were negatively impacted by higher depreciation expense related to capital expansion projects completed in previous years.

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

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages and rig activity)						
Operating revenues	$ 701,223	$ 444,665	$ 412,243	$ 256,558	58%	$ 32,422	8%
Adjusted income derived from operating activities	$ 74,725	$ 31,597	$ 28,950	$ 43,128	136%	$ 2,647	9%
Rig hours	791,956	643,813	590,878	148,143	23%	52,935	9%

Operating results increased from 2010 to 2011 primarily due to increases in rig and truck utilization facilitated by capital invested to increase rig and truck fleets as well as frac tank counts. Equipment utilization and price improvements experienced in 2011 were primarily driven by sustained higher oil prices.

Operating results increased from 2009 to 2010 primarily due to an increase in rig utilization driven by higher oil prices. The increase in operating results also reflects lower general and administrative costs and depreciation expense.

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

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages and rig activity)						
Operating revenues	$ 170,727	$ 123,761	$ 157,305	$ 46,966	38%	$ (33,544)	(21)%
Adjusted income derived from operating activities	$ 843	$ 9,245	$ 30,508	$ (8,402)	(91)%	$ (21,263)	(70)%
Rig years	9.6	9.4	11.0	0.2	2%	(1.6)	(15)%

Operating revenues increased from 2010 to 2011 as a result of higher workover activities by the Sundowner® platform and jackup rigs and from profits related to a major construction project. Adjusted income

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derived from operating activities decreased from 2010 to 2011 primarily due to lower utilization for the MODS® rigs and SuperSundowner™ platform rigs. Drilling permits have been subject to a lengthy and stringent safety and environmental review process since the Gulf of Mexico blowout in mid-2010.

The decrease in operating results from 2009 to 2010 primarily resulted from receiving standby rates and lower utilization for the MODS® rigs, SuperSundowner™ platform rigs and Sundowner® platform rigs. Drilling activities significantly declined as our customers suspended their operations in the Gulf of Mexico, largely as a result of their inability to procure government permits.

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

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages and rig activity)						
Operating revenues and Earnings from unconsolidated affiliates	$ 129,894	$ 179,218	$ 204,407	$ (49,324)	(28)%	$ (25,189)	(12)%
Adjusted income derived from operating activities	$ 27,671	$ 51,896	$ 62,742	$ (24,225)	(47)%	$ (10,846)	(17)%
Rig years	4.9	7.4	10.0	(2.5)	(34)%	(2.6)	(26)%

The decreases in operating results from 2010 to 2011 and from 2009 to 2010 were primarily due to lower average dayrates and drilling activity. While drilling activity levels decreased significantly during 2010, operating results decreased only slightly due to the acceleration of recognized deferred revenues from a significant contract that terminated.

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

		Year Ended December 31,			Increase/(Decrease)			
		2011	2010	2009	2011 to 2010		2010 to 2009	
		(In thousands, except percentages and rig activity)						
Operating revenues		$ 574,754	$ 389,229	$ 298,653	$ 185,525	48%	$ 90,576	30%
Adjusted income (loss) derived from operating activities		$ 94,637	$ 22,970	$ (7,019)	$ 71,667	312%	$ 29,989	427%
Rig years	Drilling	39.8	29.8	19.7	10.0	34%	10.1	51%
Rig hours	Well-servicing	184,908	172,589	143,824	12,319	7%	28,765	20%

Operating results increased from 2010 to 2011 primarily as a result of increases in drilling and well-servicing activity and drilling dayrates and well-servicing hourly rates. The increased drilling and well-servicing activity in Western Canada is the result of renewed interest in oil exploration, supported by strong oil commodity prices. Operating results were negatively impacted by higher drilling costs for well-servicing in 2011 for preparing service rigs for high utilization and additional labor costs for crew travel, retention and training.

Operating results increased from 2009 to 2010 primarily as a result of an overall increase in drilling and well-servicing activity, which offset the decline in average drilling dayrates and well-servicing hourly rates. The increased drilling activity in Western Canada was the result of renewed interest in oil exploration supported by sustained improved oil prices. The well-servicing hourly rate decreased during 2010 as a result of customer discounts to maintain market share. Our operating results were also positively impacted during 2010 by cost reduction efforts, mainly in general and administrative expenses.

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

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages and rig activity)						
Operating revenues and Earnings from unconsolidated affiliates	$ 1,104,461	$ 1,093,608	$ 1,265,097	$ 10,853	1%	$ (171,489)	(14)%
Adjusted income derived from operating activities	$ 123,813	$ 254,744	$ 365,566	$ (130,931)	(51)%	$ (110,822)	(30)%
Rig years	105.3	97.8	100.2	7.5	8%	(2.4)	(2)%

Operating revenues and Earnings from unconsolidated affiliates increased from 2010 to 2011 as a result of increases in the utilization of our overall rig fleet albeit at lower margins. Adjusted income derived from operating activities decreased from 2010 to 2011 primarily from the decreases in average dayrates and lower utilization of our jackup rigs in Saudi Arabia and other drilling activities in Qatar and Australia.

The decrease in operating results from 2009 to 2010 resulted primarily from year-over-year decreases in average dayrates and lower utilization of rigs in Saudi Arabia, Mexico, Kazakhstan, and Oman, driven by changes in our customers drilling programs and longer lead times for formalization of project requirements in our key markets. Operating results were further negatively impacted by higher depreciation expense related to capital expansion projects completed in recent years.

Pressure Pumping. The results of operations for this segment were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages and rig activity)						
Operating revenues	$ 1,237,306	$ 321,295	$	$ 916,011	285%	$ 321,295	100%
Adjusted income derived from operating activities	$ 229,125	$ 66,651	$	$ 162,474	244%	$ 66,651	100%

Operating results reflect our acquisition of Superior for the year ended December 31, 2011 and the period September 10, 2010 through December 31, 2010. See Note 5 Acquisitions in Part II, Item 8. Financial Statements and Supplementary Data.

Oil and Gas. The results of operations for this segment reflect our proportionate share of earnings and losses from our unconsolidated U.S. oil and gas joint venture. The results were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages)						
Earnings (losses) from unconsolidated affiliates	$ 59,685	$ 18,657	$ (182,654)	$ 41,028	220%	$ 201,311	110%

Earnings (losses) from unconsolidated affiliates increased from 2010 to 2011 as a result of operating activities from our unconsolidated U.S. oil and gas joint venture. During 2011, operating results included bargain purchase gains from multiple acquisitions of developed and undeveloped acreage. Our proportionate share of the gains totaled $49.5 million. A full-cost ceiling writedown of $15.6 million, representing our proportionate share, partially offset the positive operating results.

Earnings (losses) from unconsolidated affiliates increased from 2009 to 2010 because our unconsolidated U.S. oil and gas joint venture recorded a full-cost ceiling test writedown during 2009, of which our proportionate

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share totaled $189.3 million. The writedown resulted from the application of the full-cost method of accounting for costs related to oil and natural gas properties. Operating results for our U.S. oil and gas joint venture, excluding the full-cost ceiling test writedown, improved from 2009 to 2010.

Other Operating Segments

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

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2010 to 2009		2009 to 2008	
	(In thousands, except percentages)						
Operating revenues and Earnings from unconsolidated affiliates	$ 674,206	$ 427,154	$ 417,531	$ 247,052	58%	$ 9,623	2%
Adjusted income derived from operating activities	$ 55,617	$ 42,401	$ 35,319	$ 13,216	31%	$ 7,082	20%

The increase in operating results from 2010 to 2011 and from 2009 to 2010 primarily resulted from higher demand in the United States and Canada drilling markets for top-drives, rig instrumentation and data collection services from oil and gas exploration companies and higher third-party rental and rigwatch units, which generate higher margins, partially offset by a continued decline in customer demand for our construction services in Alaska.

Discontinued Operations

During 2010, we began actively marketing our oil and gas assets in the Horn River basin in Canada and in the Llanos basin in Colombia. These assets included our 49.7% ownership interest in Remora, and then 50.0% ownership interest in SMVP, both of which we accounted for using the equity method of accounting. All of these assets are included in our Oil and Gas operating segment.

In June 2011, the equity owners of SMVP dissolved the partnership and a proportionate share of the assets and liabilities were conveyed to us in exchange for our ownership interest. We continue to market these assets for sale and believe that they are properly reflected in our assets held for sale balances at December 31, 2011.

During 2011, we sold some of our wholly owned oil and gas assets in Colombia. We received proceeds of $89.2 million from this sale and recognized a gain of approximately $39.6 million. Additionally during 2011, Remora completed sales of its oil and gas assets in Colombia. Remora received gross proceeds of approximately $333.1 million from these sales and has made cash distributions to us in the amount of $143.0 million, with a final distribution expected upon dissolution of the joint venture.

During the fourth quarter of 2011, we announced our intention to dispose of a significant portion of our oil and gas portfolio, and accordingly reclassified the carrying value of our wholly owned U.S. oil and gas assets to assets held for sale at December 31, 2011. During the fourth quarter of 2011, we also determined that one of our Canadian subsidiaries that provides logistics services for onshore drilling using helicopter and fixed-wing aircraft met the accounting criteria of assets held for sale. Based on quoted market prices, the carrying value of the assets was adjusted to its fair value, resulting in an impairment of $7.9 million, which is included in discontinued operations for the year ended December 31, 2011. We reclassified the adjusted carrying value of these assets to assets held for sale at December 31, 2011.

On December 14, 2011, we sold our 25% working interest in the Cat Canyon and West Cat Canyon fields in Santa Barbara County, California. We received proceeds of approximately $71.6 million from the sale and recognized a gain of approximately $7.2 million.

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At December 31, 2011, our consolidated balance sheet included a current liability of discontinued operations of $54.3 million that is included in other liabilities and a noncurrent liability of discontinued operations of $71.4 million that is included in other long-term liabilities.

The operating results from the assets discussed above for all periods presented are retroactively presented and accounted for as discontinued operations in the accompanying audited consolidated statements of income (loss)**.** Our condensed statements of income (loss) from discontinued operations for the years ended December 31, 2011, 2010 and 2009 were as follows:

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
			(In thousands, except percentages)				
Revenues	$ 78,826	$ 77,992	$ 30,136	$ 834	1%	$ 47,856	159%
Earnings (losses) from unconsolidated affiliates	$ 76,541(1)	$ (10,638)	$ (59,249)(2)	$ 87,179	820%	$ 48,611	82%
Income (loss) from discontinued operations, net of tax							
Income (loss) from discontinued operations, net of tax	$ (97,440)(3)	$ (161,090)(4)(7)	$ (218,609)(5)(6)	$ 63,650	40%	$ 57,519	26%

(1) Includes approximately $83 million of equity in earnings during 2011 for our proportionate share of Remora s net income, inclusive of the gains recognized for asset sales during 2011.

(2) Includes our proportionate share of full-cost ceiling test writedowns of $47.8 million in 2009.

(3) Includes impairments of $255.0 million to write down the carrying value of our wholly owned oil and gas-centered assets, including $27.2 million related to an oil and gas financing receivable that was deemed uncollectible.

(4) Includes impairments of $192.2 million related to our wholly owned oil and gas assets. Of this total, $137.8 million represented writedowns to the carrying value of some acreage in the United States, which we currently do not have future plans to develop due to sustained low natural gas prices, and certain exploratory wells in Colombia, which we determined were uneconomical to develop in the foreseeable future. The remaining $54.3 million related to impairment of an oil and gas financing receivable and was determined using discounted cash flow models, a Level 3 measurement, and involved assumptions based on estimated cash flows for proved and probable reserves, undeveloped acreage value, and current and expected natural gas prices.

(5) Includes impairments totaling $205.9 million to some of our wholly owned oil and gas assets. We recognized an impairment of $149.1 million to a financing receivable as a result of commodity price deterioration and the lower price environment lasting longer than expected. The prolonged period of lower prices significantly reduced demand for future gas production and development in the Barnett Shale area of north central Texas and influenced our decision not to expend capital to develop on some of the undeveloped acreage. Annual impairment tests on our U.S. wholly owned oil and gas properties resulted in impairment charges of $56.8 million to write down the carrying value of some acreage that we do not have future plans to develop.

(6) Includes $14.7 million to impair the remaining goodwill balance of Nabors Blue Sky Ltd. as a result of our annual goodwill impairment tests. We determined the impairment charge was 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.

(7) Includes $7.5 million of impairment to our aircraft and some drilling equipment during the year ended December 31, 2010. These impairment charges resulted from annual impairment tests on long-lived assets.

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Additional discussion of our policy pertaining to the calculations of our annual impairment tests, including any impairment of goodwill, is set forth in 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. Additional information relating to discontinued operations is provided in Notes 4 Discontinued Operations and 24 Supplemental Information on Oil and Gas Exploration and Production Activities in Part II, Item 8. Financial Statements and Supplementary Data. A further protraction of lower commodity prices or an inability to sell these assets in a timely manner could result in recognition of future impairment charges.

OTHER FINANCIAL INFORMATION

General and administrative expenses

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages)						
General and administrative expenses	$ 489,892	$ 338,720	$ 421,492	$ 151,172	45%	$ (82,772)	(20)%
General and administrative expenses as a percentage of operating revenues	8.1%	8.2%	11.5%	(.1)%	1%	(3.3)%	(29)%

General and administrative expenses increased from 2010 to 2011 primarily as a result of increases in wages to support a higher headcount as a result of (i) our Superior acquisition in September 2010 and (ii) increased operations for a majority of our operating segments. As a percentage of operating revenues, general and administrative expenses decreased from 2010 to 2011.

General and administrative expenses decreased from 2009 to 2010 primarily as a result of significant decreases in wage-related expenses and other cost-reduction efforts across all business units.

Depreciation and amortization, and depletion expense

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages)						
Depreciation and amortization expense	$ 924,094	$ 760,962	$ 663,958	$ 163,132	21%	$ 97,004	15%

Depreciation and amortization expense increased from 2010 to 2011 and from 2009 to 2010 as a result of the incremental depreciation expense from (i) pressure pumping assets acquired in September 2010, (ii) newly constructed rigs recently placed into service and (iii) rig upgrades and other capital expenditures made during 2010 and 2011.

Interest expense

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages)						
Interest expense	$ 256,633	$ 272,712	$ 266,047	$ (16,079)	(6)%	$ 6,665	3%

Interest expense decreased from 2010 to 2011 as a result of repurchases during 2010 and the redemption in May 2011 for a total of $2.6 billion in par value of the 0.94% senior exchangeable notes over 2010 and 2011. The decrease was partially offset by additional interest related to our August 2011 issuance of 4.625% senior notes due September 2021, a full year of interest on our September 2010 issuance of 5.0% senior notes due September 2020 and interest on amounts outstanding on our revolving credit facilities.

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Interest expense increased from 2009 to 2010 as a result of the interest expense related to our September 2010 issuance of 5.0% senior notes due September 2020. The increase was partially offset by a reduction to interest expense resulting from our repurchases of approximately $1.2 billion par value of 0.94% senior exchangeable notes during 2009 and 2010.

Investment income (loss)

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages)						
Investment income (loss)	$ 19,940	$ 7,263	$ 25,522	$ 12,677	175%	$ (18,259)	(72)%

Investment income during 2011 was $19.9 million and included (i) a $12.9 million realized gain relating to one of our overseas fund investments classified as long-term investments, (ii) $5.1 million realized gains from short-term and other long-term investments and (iii) $9.9 million interest and dividend income from our cash, other short-term and long-term investments. Investment income was partially offset by net unrealized losses of $8.0 million from our trading securities.

Investment income during 2010 was $7.3 million and included interest and dividend income of $7.5 million from our cash, other short-term and long-term investments and $4.2 million from gains on sales of short-term and long-term investments, partially offset by net unrealized losses of $4.4 million from our trading securities.

Investment income during 2009 was $25.5 million and included net unrealized gains of $9.8 million from our trading securities and interest and dividend income of $15.8 million from our cash, other short-term and long-term investments.

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

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages)						
Gains (losses) on sales and retirements of long-lived assets and other income (expense), net	$ (4,514)	$ (47,238)	$ (11,982)	$ (42,724)	(90)%	$ 35,256	294%

The amount of losses (gains) on sales and retirements of long-lived assets and other expense (income), net for 2011 was a net loss of $4.5 million and was comprised of (i) increases to our litigation reserves of $11.3 million, (ii) foreign currency exchange losses of approximately $5.5 million and (iii) a net loss on sales and retirements of long-lived assets of approximately $1.9 million. The net loss was partially offset by a $13.1 million gain recognized in connection with our acquisition of the remaining 50 percent equity interest of Peak.

The amount of gains (losses) on sales and retirements of long-lived assets and other income (expense), net for 2010 represented a net loss of $47.2 million and included: (i) foreign currency exchange losses of approximately $18.1 million, (ii) litigation expenses of $6.4 million, (iii) net losses on sales and retirements of long-lived assets of approximately $6.4 million, (iv) acquisition-related costs of $7.0 million and (v) losses of $7.0 million recognized on purchases 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 2009 represented a net loss of $12.0 million and included: (i) foreign currency exchange losses of approximately $8.0 million, (ii) 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.

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Impairments and Other Charges

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
	(In thousands, except percentages)						
Provision for termination payment	$ 100,000	$	$	$ 100,000	100%	$	
Provision for retirement of long-lived assets	98,072	23,213	64,229	74,859	322%	(41,016)	(64)%
Impairment of long-lived assets		27,372		(27,372)	(100)%	27,372	100%
Goodwill impairments		10,707		(10,707)	(100)%	10,707	100%
Other-than-temporary impairment of equity security			18,665			(18,665)	(100)%
Other-than-temporary impairment of securities			35,649			(35,649)	(100)%
Total	$ 198,072	$ 61,292	$ 118,543	$ 136,780	223%	$ (57,251)	(48)%

Provision for termination payment

During the fourth quarter of 2011, we recorded a provision for a contingent liability that existed on December 31, 2011 related to the change of our Chief Executive Officer that occurred in October. This charge resulted from the potential termination payment to our former Chief Executive Officer, Mr. Isenberg, under the terms of his employment contract. Subsequent to December 31, 2011, Mr. Isenberg elected to forego triggering that payment, and as a result, the Company does not owe the termination payment. In connection with that development, the Company announced plans to make charitable contributions to benefit the needs of its employees and other community-based causes. The Company contributed one million Nabors common shares previously held by an affiliate to the Nabors Charitable Foundation, a 501(c)(3) organization, in support of this objective. The election of Mr. Isenberg to forego triggering the potential payment, offset by the charitable contributions described above, will be recorded as a capital contribution during the first quarter of 2012.

Provision for retirement of long-lived assets

During 2011, we recorded a provision for retirement of long-lived assets totaling $98.1 million in multiple operating segments. This related to the decommissioning and retirement of one jackup rig, 116 land rigs, and a number of rigs for well-servicing and trucks. Our U.S. Lower 48 Land Drilling, International and U.S. Land Well-servicing operations recorded $63.2 million, $26.1 million and $8.9 million, respectively. These assets were deemed to be functionally or economically non-competitive for today s market and are being dismantled for parts and scrap.

During 2010, we recorded a provision for retirement of long-lived assets totaling $23.2 million related to the abandonment of certain rig components, comprised of engines, top-drive units, building modules and other equipment that has become obsolete or inoperable in our U.S. Lower 48 Land Drilling, U.S. Land Well-servicing and U.S. Offshore Contract Drilling operating segments.

During 2009, we recorded a provision for retirement of long-lived assets totaling $64.2 million related to assets in our U.S. Offshore, Alaska, Canada and International Contract Drilling operating segments. The retirements included inactive workover jackup 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.

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Impairments of Long-Lived Assets

We did not record any impairment of long-lived assets in 2011. During 2010, we recognized $27.3 million in impairment charges related to some jackup rigs in our U.S. Offshore operating segment. These impairment charges stemmed from our annual impairment tests on long-lived assets.

The impairments and other charges, inclusive of the provisions for retirement and impairments of long-lived assets, recognized during 2011, 2010 and 2009 were determined necessary as a result of continued lower commodity prices and uncertainty in the oil and gas environment and its related impact on drilling and well-servicing activity and our dayrates. A prolonged period of legislative uncertainty in our U.S. Offshore operations, or continued 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.

Goodwill Impairments

We did not record any goodwill impairment in 2011. In 2010, we recognized an impairment of approximately $10.7 million relating to our goodwill balance of our U.S. Offshore operating segment. The impairment charge stemmed from our annual impairment test on goodwill, which compared the estimated fair value of each of our reporting units to its carrying value. The estimated fair value of our U.S. Offshore segment was determined using discounted cash flow models involving assumptions based on our utilization of rigs and revenues as well as direct costs, general and administrative costs, depreciation, applicable income taxes, capital expenditures and working capital requirements. We determined that the fair value estimated for purposes of this test represented a Level 3 fair value measurement. The impairment charge was deemed necessary due to the uncertainty of utilization of some of our rigs as a result of changes in our customers plans for future drilling operations in the Gulf of Mexico. Many of our customers suspended drilling operations in the Gulf of Mexico, largely as a result of their inability to obtain government permits. Although the U.S. deepwater drilling moratorium has been lifted, our customers have continued to encounter delays in obtaining government permits. It is uncertain when this will improve. A significantly prolonged period of lower oil and natural gas prices or changes in laws and regulations 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.

Other than Temporary Impairments of Debt and Equity Securities

We did not record any other-than-temporary impairments in 2011 or 2010. During 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 of time, we determined the investment was other than temporarily impaired and it was appropriate to write down its carrying value to its estimated fair value.

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Income tax rate

	Year Ended December 31,			Increase/(Decrease)			
	2011	2010	2009	2011 to 2010		2010 to 2009	
Effective income tax rate from continuing operations	29%	13%	(93)%	16%	123%	106%	114%

The increase in our effective tax rate from 2010 to 2011 is mainly a result of the increase in the proportion of income generated in the United States versus the international jurisdictions in which we operate. Income generated in the United States is generally taxed at a higher rate than international jurisdictions.

Our effective income tax rate for 2010 and 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. During 2009, the result was a net tax benefit. In 2009, that benefit represented a significant percentage of our consolidated loss from continuing operations before income taxes. Because of the manner in which that number is derived, we do not believe it presents a meaningful basis for comparing our 2009 effective income tax rate to the 2010 effective income tax rate.

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. 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 audited 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 U.S. 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.

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, 2011 and 2010.

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Operating Activities. Net cash provided by operating activities totaled $1.5 billion during 2011 compared to net cash provided by operating activities of $1.1 billion during 2010. 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 $1.5 billion and $1.3 billion for the years ended December 31, 2011 and 2010, 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 used $36.7 million and $202.4 million, respectively, in cash flows for the years ended December 31, 2011 and 2010.

Investing Activities. Net cash used for investing activities totaled $1.9 billion during 2011 compared to net cash used for investing activities of $1.7 billion during 2010. The primary use of cash for investing activities is for capital expenditures related to rig-related enhancements, new construction and equipment, as well as sustaining capital expenditures. During 2011 and 2010, we used cash for capital expenditures totaling $2.0 billion and $930.3 million, respectively.

During 2011, we used cash of $55.5 million to acquire the remaining equity interest of Peak. During 2010, we used cash of $680.2 million and $53.4 million, respectively, to acquire Superior (net of the cash acquired) and the assets of Energy Contractors. During 2011, cash of $71.6 million and $89.2 million was provided in proceeds from sales of our oil and gas assets in the United States and Colombia, respectively. During 2011 and 2010, we provided cash of $112.3 million and $40.9 million, respectively, to our unconsolidated affiliates. Additionally during 2011, we received distributions of $143.0 million from Remora related to proceeds it received from the sale of its oil and gas assets in Colombia.

Financing Activities. Net cash provided by financing activities totaled $163.2 million during 2011 compared to net cash provided by financing activities of $280.3 million during 2010. During 2011, we have drawn $1.6 billion from our revolving credit facilities primarily for the redemption of the remaining $1.4 billion of our 0.94% senior exchangeable notes. During 2011, cash was provided from the receipt of $690.4 million in proceeds, net of debt issuance costs, from the issuance by Nabors Delaware of its 4.625% senior notes due September 2021 in August 2011 and was used to repay amounts then outstanding under the revolving credit facilities.

During 2010, cash was provided from the receipt of $682.3 million in proceeds, net of debt issuance costs, from the issuance by Nabors Delaware of its 5.0% senior notes due September 2020 in September 2010 and we used cash to purchase $273.9 million of our 0.94% senior exchangeable notes and to repay $124.0 million of Superior s revolving credit facility and second lien notes.

During 2011 and 2010, cash was provided by our receipt of proceeds totaling $11.6 million and $8.2 million, respectively, from the exercise by our employees of options to acquire our common shares.

Future Cash Requirements

We expect capital expenditures over the next 12 months to approximate $1.5-1.7 billion. We had outstanding purchase commitments of approximately $1.0 billion at December 31, 2011, primarily for rig-related enhancements, new construction and equipment, as well as sustaining capital expenditures, other operating expenses and purchases of inventory. 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 12 months represent a number of capital programs that are currently underway or planned. These programs will result in an expansion in the number of land drilling rigs, pressure pumping and well-servicing equipment that we own and operate. We can reduce the planned expenditures if necessary, or increase them if market conditions and new business opportunities warrant it.

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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 debt or our common shares. Future acquisitions may be paid for using existing cash or by issuing debt or additional shares of our stock. 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).

The following table summarizes our contractual cash obligations as of December 31, 2011:

	Payments due by Period				
	Total	**< 1 Year**	**1-3 Years (In thousands)**	**3-5 Years**	**Thereafter**
Contractual cash obligations:					
Long-term debt:(1)					
Principal	$ 4,635,000	$ 275,000(2)	$ 860,000(3)	$	$ 3,500,000(4)
Interest	1,823,925	246,213	462,911	462,826	651,975
Operating leases(5)	80,861	25,288	34,423	11,293	9,857
Purchase commitments(6)	962,235	774,617	128,648	58,970	
Employment contracts(5)	14,158	9,752	3,905	501	
Pension funding obligations	1,508	1,508			
Transportation and Processing Contracts(7)	388,699	54,287	134,429	113,175	86,808
Total contractual cash obligations	$ 7,906,386	$ 1,386,665	$ 1,624,316	$ 646,765	$ 4,248,640

The table above excludes liabilities for unrecognized tax benefits totaling $97.0 million as of December 31, 2011 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 13 Income Taxes in Part II, Item 8. Financial Statements and Supplementary Data.

(1) See Note 12 Debt in Part II, Item 8. Financial Statements and Supplementary Data.

(2) Includes Nabors Delaware s 5.375% senior notes due August 2012.

(3) Represents amounts drawn on revolving credit facilities, which expire September 2014.

(4) Represents Nabors Delaware s aggregate 6.15% senior notes due February 2018, 9.25% senior notes due January 2019, 5.0% senior notes due September 2020 and 4.625% senior notes due September 2021.

(5) See Note 18 Commitments and Contingencies in Part II, Item 8. Financial Statements and Supplementary Data.

(6) 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.

(7) We have contracts with pipeline companies to pay specified fees based on committed volumes for gas transport and processing, as calculated on a monthly basis. Due to low natural gas prices and our decision to delay drilling, our current available production flowing to pipelines and processing plants does not meet the daily committed volumes required under the contracts. The amounts set forth in the table above reflect the aggregate fees payable under these contracts. See Note 18 Commitments and Contingencies in Part II, Item 8. Financial Statements and Supplementary Data.

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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.

See Note 18 Commitments and Contingencies in Part II, Item 8. Financial Statements and Supplementary Data for discussion of commitments and contingencies relating to (i) our employment agreement with Mr. Petrello that could result in a significant cash payment of $50 million by the Company if his employment were terminated in the event of death or disability or a cash payment of approximately $31.1 million if his employment were 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, availability under our various revolving credit facilities, and cash generated from operations. As of December 31, 2011, we had cash and investments of $539.5 million and working capital of $1.3 billion. We also had $540 million of availability remaining from a combined total of $1.4 billion under revolving credit facilities. At December 31, 2010, we had cash and investments of $801.2 million and working capital of $458.6 million.

On August 23, 2011, Nabors Delaware completed a private placement of $700 million aggregate principal amount of 4.625% senior notes due 2021, which are unsecured and fully and unconditionally guaranteed by us. The notes have registration rights. The notes rank equal in right of payment to all of Nabors Delaware s existing and future unsubordinated indebtedness, and senior in right of payment to all of Nabors Delaware s existing and future senior subordinated and subordinated indebtedness. Our guarantee of the notes is unsecured and an unsubordinated obligation and ranks equal in right of payments to all of our unsecured and unsubordinated indebtedness from time to time outstanding. In the event of a change of control triggering event, as defined in the indenture, the holders of the notes may require Nabors Delaware to purchase all or a portion of the notes at a purchase price equal to 101% of their principal amount, plus accrued and unpaid interest, if any. The notes are redeemable in whole or in part at any time at the option of Nabors Delaware at a redemption price, plus accrued and unpaid interest, as specified in the indenture. We used a substantial portion of the proceeds from this offering to repay borrowings outstanding under our revolving credit facilities.

As of December 31, 2011, we had $540 million of remaining availability from a combined total of $1.4 billion under our existing revolving credit facilities. The existing revolving credit facilities mature in September 2014, and can be used for general corporate purposes, including capital expenditures and working capital.

During 2011, we sold some of our wholly owned oil and gas assets and received cash proceeds of $160.8 million. Additionally, Remora completed sales of its oil and gas assets and made cash distributions to us in the amount of $143.0 million.

We had six letter-of-credit facilities with various banks as of December 31, 2011. Availability under these facilities as of December 31, 2011 was as follows:

	(In thousands)
Credit available	$ 215,901
Letters of credit outstanding, inclusive of financial and performance guarantees	(80,408)
Remaining availability	$ 135,493

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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 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, in addition to our other cash obligations, would not ultimately have a material adverse impact on our liquidity or financial position. A credit downgrade may impact our ability to access credit markets.

Our gross funded debt to capital ratio was 0.43:1 as of December 31, 2011 and 0.42:1 as of December 31, 2010. Our net funded debt to capital ratio was 0.40:1 as of December 31, 2011 and 0.38:1 as of December 31, 2010.

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 investments. 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 8.1:1 as of December 31, 2011 and 7.0:1 as of December 31, 2010. The interest coverage ratio is a trailing 12-month quotient of the sum of (x) income (loss) from continuing operations, net of tax, net income (loss) attributable to noncontrolling interest, interest expense, subsidiary preferred stock dividends, depreciation and amortization, impairments and other charges, income tax expense (benefit) and our proportionate share of writedowns from our unconsolidated oil and gas joint venture *less* investment income (loss) *divided* by (y) the sum of cash interest expense and subsidiary preferred stock dividends. 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.

Our current cash and investments, projected cash flows from operations, possible dispositions of non-core assets and our revolving credit facilities are expected to adequately finance our purchase commitments, scheduled debt service requirements, and all other expected cash requirements for the next 12 months.

See our discussion of the impact of changes in market conditions on our derivative financial instruments 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. 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.

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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:

	Maximum Amount				
	2012	2013	2014	Thereafter	Total
			(In thousands)		
Financial standby letters of credit and other financial surety instruments	$ 105,055	$ 38	$	$	$ 105,093

Other Matters

Recent Accounting Pronouncements

In December 2008, the SEC issued a Final Rule, Modernization of Oil and Gas Reporting. This rule revised 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 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 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 were effective for registration statements filed on or after January 1, 2010 and for annual financial statements filed on or after December 31, 2009. 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 were considered with operating results from our unconsolidated oil and gas joint ventures, which we account for under the equity method of accounting, we had significant oil and gas activities under the new definition. Our oil and gas disclosures for the years ending December 31, 2011 and 2010 are provided in Note 24 Supplemental Information on Oil and Gas Exploration and Production Activities in Part II Item 8. Financial Statements and Supplementary Data.

Effective January 1, 2010, we adopted the revised provisions relating to consolidation of variable interest entities within the Consolidations Topic of the FASB s Accounting Standards Codification (ASC). The revised provisions replaced the quantitative approach to identify a variable interest entity with a qualitative approach that focuses on an entity s control and ability to direct the variable interest entity s activities. The application of these provisions did not have a material impact on our consolidated financial statements.

The FASB issued new guidance relating to revenue recognition for contractual arrangements with multiple revenue-generating activities. The ASC Topic for revenue recognition includes identification of a unit of accounting and how arrangement consideration should be allocated to separate the units of accounting, when applicable. The new guidance, including expanded disclosures, became applicable to us for contracts entered into after June 15, 2010. The adoption of these rules did not have a significant impact on our consolidated financial statements.

In May 2011, the FASB issued an Accounting Standards Update (ASU) to clarify the application of some of the existing fair value measurement and disclosure requirements. These changes are effective for interim and annual periods that begin after December 15, 2011. The disclosure requirements did not have a significant impact on our consolidated financial statements.

In June 2011, the FASB issued an ASU relating to the presentation of other comprehensive income (OCI). This ASU does not change the items that are reported in OCI, but does remove the option to present the components of OCI within the statement of changes in equity. In addition, this ASU will require OCI presentation on the face of the financial statements. These changes are effective for interim and annual periods

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that begin after December 15, 2011, and are applied retrospectively to all periods presented. Early adoption is permitted. We adopted the ASU beginning January 1, 2012, and it did not have an impact on our consolidated financial statements.

In September 2011, the FASB issued a revised ASU relating to goodwill impairment tests. An entity is allowed to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on its qualitative assessment, that it is more likely than not that the fair value is less than its carrying amount. The amendment is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011 and early adoption is permitted. We adopted the ASU beginning January 1, 2012 and will apply it to our goodwill impairment tests.

Related-Party Transactions

The Company and Nabors Delaware entered into an agreement with Eugene M. Isenberg, the Chairman of our Board of Directors, on February 2, 2012 but effective December 31, 2011, pursuant to which:

- Mr. Isenberg voluntarily terminated both his employment with the Company and his Employment Agreement, and forwent any right to payment in connection with such termination, including a possible payment of $100 million in connection with the Company s appointment of a new chief executive officer on October 28, 2011, which Mr. Isenberg could have treated as a constructive termination under his employment agreement;

- Mr. Isenberg will continue as Chairman of the Board, but will not stand for reelection as a director when his term expires in June 2012; at that time, he will be appointed Chairman Emeritus for a three-year term, which will be extended for additional one-year terms unless terminated by him or by the Company, and receive cash compensation equal to other nonemployee directors;

- Nabors Delaware will pay $6,600,000 into an escrow account, which will bear interest at the guaranteed rate of 6% per annum compounded daily and will be distributed either to Mr. Isenberg s estate or to the trustees of his revocable trust;

- Mr. Isenberg ceases participation in the Company s benefit plans and forfeits any benefits available to him thereunder (including forfeiture of the balance in his deferred bonus account), except as stated below or otherwise required by law:

  - he and his spouse continue to participate in medical, dental and life insurance coverage until either receives equivalent coverage and benefits under the plans and programs of a subsequent employer or their death;

  - he remains entitled to distribution of vested account balances in the Company s 401(k) plan and its Deferred Compensation Plan;

  - he retains certain benefits under the split-dollar life insurance agreements in effect between him and Nabors Delaware

- all of Mr. Isenberg s stock option and restricted stock awards were already fully vested and remain subject to the applicable plans and agreements governing them; and

Mr. Isenberg waives all claims or other liabilities related to his Employment Agreement or his termination of employment, and the Company waives certain claims against Mr. Isenberg.

Nabors and certain key employees, including Messrs. Isenberg and Petrello, entered into split-dollar life insurance agreements, pursuant to which we paid a portion of the premiums under life insurance policies with respect to these individuals and, in some instances, members of their families. These agreements provide that we are reimbursed the premium payments upon the occurrence of specified events, including the death of an insured individual. We will not be reimbursed for the premium payments paid on behalf of Mr. Isenberg as provided by the agreement entered into on February 2, 2012. Any recovery of premiums paid by Nabors could be limited to the cash surrender value of the policies under certain circumstances. As such, the values of these policies are recorded at their respective cash surrender values in our consolidated balance sheets. We have made premium payments to date totaling $6.3 million related to these policies. The cash surrender value of these policies of approximately $5.8 million and $9.5 million is included in other long-term assets in our consolidated balance sheets as of December 31, 2011 and 2010, respectively.

Under the Sarbanes-Oxley Act of 2002, the payment of premiums by Nabors under the agreements with Messrs. Isenberg and Petrello could be deemed to be prohibited loans by us to these individuals. Consequently, we have paid no premiums related to our agreements with these individuals since the adoption of the Sarbanes-Oxley Act.

In the ordinary course of business, we enter into various rig leases, rig transportation and related oilfield services agreements with our unconsolidated affiliates at market prices. Revenues from business transactions with these affiliated entities totaled $218.4 million, $271.6 million and $327.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. Expenses from business transactions with these affiliated entities totaled $.9 million, $3.4 million and $9.8 million for the years ended December 31, 2011, 2010 and 2009, respectively. Additionally, we had accounts receivable from these affiliated entities of $110.7 million and $97.8 million as of December 31, 2011 and 2010, respectively. We had accounts payable to these affiliated entities of $46.1 million and $12.7 million as of December 31, 2011 and 2010, respectively, and long-term payables with these affiliated entities of $.8 million as of each of December 31, 2011 and 2010, which is included in other long-term liabilities.

In addition to the equity investment in our unconsolidated U.S. oil and gas joint venture, in April 2010 we purchased $20.0 million face value of NFR Energy LLC s 9.75% senior notes. These notes mature in 2017 with interest payable semi-annually on February 15 and August 15. During 2011 and 2010, we recognized $2.0 million and $1.4 million, respectively, in interest income from these notes.

We own an interest in Shona Energy Company, LLC (Shona), a company of which Mr. Payne, an independent member of our Board of Directors, is the Chairman and Chief Executive Officer. During the first quarter of 2010, we purchased shares of Shona s preferred stock and warrants to purchase additional common shares for $.9 million, which we had accounted for under the cost method of accounting. During 2011, Shona became a public company in Canada, with voting common shares listed on the TSX Venture Exchange. As of December 31, 2011, we held a minority interest of approximately 7.55% of the issued and outstanding common shares of Shona. The fair value of this equity security investment is $10.5 million.

Critical Accounting Estimates

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

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

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

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

Financial Instruments. As defined in the ASC, fair value is the price that would be received upon a sale of an asset or paid upon a transfer of a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market-corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best information available. Accordingly, we employ valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The use of unobservable inputs is intended to allow for fair value determinations in situations where there is little, if any, market activity for the asset or liability at the measurement date. We are able to classify fair value balances utilizing a fair-value hierarchy based on the observability of those inputs. Under the fair-value hierarchy:

- Level 1 measurements include unadjusted quoted market prices for identical assets or liabilities in an active market;

- Level 2 measurements include quoted market prices for identical assets or liabilities in an active market that have been adjusted for items such as effects of restrictions for transferability and those that are not quoted but are observable through corroboration with observable market data, including quoted market prices for similar assets; and

- Level 3 measurements include those that are unobservable and of a highly subjective measure.

Depreciation of Property, Plant and Equipment. The drilling, workover and well-servicing and pressure pumping industries are very capital intensive. Property, plant and equipment represented 67% of our total assets as of December 31, 2011, and depreciation constituted 16.4% of our total costs and other deductions for the year ended December 31, 2011.

Depreciation for our primary operating assets, drilling and workover rigs, is calculated based on the units-of-production method. For each day a rig is operating, we depreciate it over an approximate 4,900-day period, with the exception of our jackup rigs which are depreciated over an 8,030-day period, after provision for salvage value. For each day a rig asset is not operating, it is depreciated over an assumed depreciable life of 20 years, with the exception of our jackup rigs, where a 30-year depreciable life is typically used, after provision for salvage value.

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

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

There have been no factors related to the performance of our portfolio of assets, changes in technology or other factors that indicate that these estimates do not continue to be appropriate. Accordingly, for the years ended

December 31, 2011, 2010 and 2009, no significant changes have been made to the depreciation rates applied to property, plant and equipment, the underlying assumptions related to estimates of depreciation, or the methodology applied. However, certain events could occur that would materially affect our estimates and assumptions related to depreciation. Unforeseen changes in operations or technology could substantially alter management s assumptions regarding our ability to realize the return on our investment in operating assets and therefore affect the useful lives and salvage values of our assets.

Impairment of Long-Lived Assets. As discussed above, the drilling, workover and well-servicing and pressure pumping industry is very capital intensive. We review our assets for impairment annually or when events or changes in circumstances indicate that the carrying amounts of property, plant and equipment may not be recoverable. An impairment loss is recorded in the period in which it is determined that the sum of estimated future cash flows, on an undiscounted basis, is less than the carrying amount of the long-lived asset. Impairment charges are recorded using discounted cash flows, which requires the estimation of dayrates and utilization, and such estimates can change based on market conditions, technological advances in the industry or changes in regulations governing the industry. Significant and unanticipated changes to the assumptions could result in future impairments. As the determination of whether impairment charges should be recorded on our long-lived assets is subject to significant management judgment, and an impairment of these assets could result in a material charge on our consolidated statements of income (loss), management believes that accounting estimates related to impairment of long-lived assets are critical.

Assumptions made in the determination of future cash flows are made with the involvement of management personnel at the operational level where the most specific knowledge of market conditions and other operating factors exists. For the years ended December 31, 2011, 2010 and 2009, no significant changes have been made to the methodology utilized to determine future cash flows.

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

Impairment of Goodwill and Intangible Assets. Goodwill represented 3.9% of our total assets as of December 31, 2011. We review goodwill and intangible assets with indefinite lives for impairment annually or more frequently if events or changes in circumstances indicate that the carrying amount of such goodwill and intangible assets exceed their fair value. During the second quarter of 2011, we performed our impairment tests of goodwill and intangible assets for all of our reporting units within our operating segments. These reporting units consist of our contract drilling segments: U.S. Lower 48 Land Drilling, U.S. Land Well-servicing, U.S. Offshore, Alaska, Canada and International; our Pressure Pumping segment; our oil and gas segment; and our other operating segments: Canrig Drilling Technology Ltd., Ryan Directional Services Inc. and Nabors Blue Sky Ltd. The impairment test involves comparing the estimated fair value of the reporting unit to its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, a second step is required to measure the goodwill impairment loss. This second step compares the implied fair value of the reporting unit s goodwill to the carrying amount of that goodwill. If the carrying amount of the reporting unit s goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess. During 2011, we concluded that all our operating segment s fair values were substantially in excess of their carrying value with the exception of the U.S. Land Well-servicing and International segments. These operating segments had an excess of fair value over carrying value of approximately 20%. Our impairment test results required the second step measurement for one reporting unit during each of 2010 and 2009.

The fair values calculated in these impairment tests are 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. Our discounted cash flow projections for each reporting unit were based on financial forecasts. The future cash flows were discounted to present value using discount rates that are

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determined to be appropriate for each reporting unit. Terminal values for each reporting unit were calculated using a Gordon Growth methodology with a long-term growth rate of 3%. We believe the fair value estimated for purposes of these tests represent a Level 3 fair value measurement.

During 2010 and 2009, we recognized goodwill impairments of approximately $10.7 million and $14.7 million, respectively. The impairment charge during 2010 was recorded in our U.S. Offshore operating segment and was deemed necessary due to the uncertainty of utilization of some of our rigs as a result of changes in our customers plans for future drilling operations in the Gulf of Mexico. Many of our customers had suspended drilling operations in the Gulf of Mexico, largely as a result of their inability to obtain government permits. During 2009, we impaired the remaining goodwill balance of $14.7 million of Nabors Blue Sky Ltd. 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 led to reduced capital spending by our customers and 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 or changes in laws and regulations could continue to 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.

As further discussed above in *Recent Accounting Pronouncements*, we changed the manner in which we initially assess goodwill for impairment during 2012. Under new guidance, we will assess qualitative factors to determine whether to perform the two-step quantitative goodwill impairment tests.

Oil and Gas Properties. 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 such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. However, these capitalized costs are subject to a ceiling test, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or market value of unproved properties. Future revenues for purposes of the ceiling test are valued using a 12-month average price, adjusted for the impact of derivatives accounted for as cash flow hedges as prescribed by the SEC rules. During 2011 and 2009, our proportionate share of those ventures full-cost ceiling test writedowns was $15.6 million and $237.1 million, respectively. No full-cost ceiling test writedowns were recorded by our unconsolidated oil and gas joint ventures during 2010.

Our wholly owned oil and gas investment portfolio and our unconsolidated ownership interest in Remora is reflected as Assets held for sale in our consolidated balance sheet at December 31, 2011. We evaluate the carrying value of our assets held for sale to the fair value of the assets less costs to sale to determine whether impairment is indicated.

A significantly prolonged period of lower oil and natural gas prices or a reduction to the estimation of reserve quantities could continue to adversely affect the demand for and prices of our services, which could result in future impairment charges to our oil and gas properties.

Oil and Gas Reserves. Evaluations of oil and gas reserves are integral to making investment decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis for calculating unit-of-production depreciation rates and for evaluating impairment. Oil and gas reserves include both proved and unproved reserves. Consistent with the definitions provided by the SEC, proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, known reservoirs, and under existing economic conditions. Unproved reserves are those with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that are more likely to be recovered than not.

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Estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process involving rigorous technical evaluations, commercial and market assessment, and detailed analysis of well information such as flow rates and reservoir pressure declines. Although we are reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in long-term oil and gas price levels.

Income Taxes. Deferred taxes represent a substantial liability for Nabors. For financial reporting purposes, management determines our current tax liability as well as those taxes incurred as a result of current operations yet deferred until future periods. In accordance with the liability method of accounting for income taxes as specified in the Income Taxes Topic of the ASC, the provision for income taxes is the sum of income taxes both currently payable and deferred. Currently payable taxes represent the liability related to our income tax return for the current year while the net deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities reported on our consolidated balance sheets. The tax effects of unrealized gains and losses on investments and derivative financial instruments are recorded through accumulated other comprehensive income (loss) within equity. The changes in deferred tax assets or liabilities are determined based upon changes in differences between the basis of assets and liabilities for financial reporting purposes and the basis of assets and liabilities for tax purposes as measured by the enacted tax rates that management estimates will be in effect when these differences reverse. Management must make certain assumptions regarding whether tax differences are permanent or temporary and must estimate the timing of their reversal, and whether taxable operating income in future periods will be sufficient to fully recognize any gross deferred tax assets. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In determining the need for valuation allowances, management has considered and made judgments and estimates regarding estimated future taxable income and ongoing prudent and feasible tax planning strategies. These judgments and estimates are made for each tax jurisdiction in which we operate as the calculation of deferred taxes is completed at that level. Further, under U.S. federal tax law, the amount and availability of loss carryforwards (and certain other tax attributes) are subject to a variety of interpretations and restrictive tests applicable to Nabors and our subsidiaries. The utilization of such carryforwards could be limited or effectively lost upon certain changes in ownership. Accordingly, although we believe substantial loss carryforwards are available to us, no assurance can be given concerning the realization of such loss carryforwards, or whether or not such loss carryforwards will be available in the future. These loss carryforwards are also considered in our calculation of taxes for each jurisdiction in which we operate. Additionally, we record reserves for uncertain tax positions that are subject to a significant level of management judgment related to the ultimate resolution of those tax positions. Accordingly, management believes that the estimate related to the provision for income taxes is critical to our results of operations. See Part I, Item 1A. Risk Factors *We may have additional tax liabilities* and Note 13 Income Taxes in Part II, Item 8. Financial Statements and Supplementary Data for additional discussion.

We are subject to income taxes in both the United States and numerous 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 audited by tax authorities. Although we believe our tax estimates are reasonable, the final determination of tax audits and any related litigation could be materially different than that reflected in historical 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. However, certain events could occur that would materially affect management s estimates and assumptions regarding the deferred portion of our income tax provision, including estimates of future tax rates applicable to the reversal of tax differences, the classification of timing differences as temporary or permanent, reserves recorded for uncertain tax positions and any valuation allowance recorded as a reduction to our deferred tax assets. Management s assumptions related to the preparation of our income tax provision have historically proved to be reasonable in light of the ultimate amount of tax liability due in all taxing jurisdictions.

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For the year ended December 31, 2011, our provision for income taxes from continuing operations was $142.6 million, consisting of $109.7 million of current tax benefit and $32.9 million of deferred tax expense. Changes in management s estimates and assumptions regarding the tax rate applied to deferred tax assets and liabilities, the ability to realize the value of deferred tax assets, or the timing of the reversal of tax basis differences could potentially impact the provision for income taxes and could potentially change the effective tax rate. A 1% change in the effective tax rate from 29% to 30% would increase the current year income tax provision by approximately $4.7 million.

Litigation and Self-Insurance Reserves. Our operations are subject to many hazards inherent in the drilling, workover and well-servicing and pressure pumping industries, including blowouts, cratering, explosions, fires, loss of well control, loss of or damage to the wellbore or underground reservoir, 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 and natural resources damage and damage to the property of others. Our offshore operations are also subject to the hazards of marine operations including capsizing, grounding, collision and other damage from hurricanes and heavy weather or sea conditions and unsound ocean bottom conditions. Our operations are subject to risks of war, civil disturbances or other political events.

Accidents may occur, we may be unable to obtain desired contractual indemnities, and our insurance may prove inadequate in certain cases. There is no assurance that such insurance or indemnification agreements will adequately protect us against liability from all of the consequences of the hazards described above. Moreover, our insurance coverage generally provides that we assume a portion of the risk in the form of a deductible or self-insured retention.

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

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

During 2011, 2010 and 2009, no significant changes were made to the methodology utilized to estimate insurance reserves. For purposes of earnings sensitivity analysis, if the December 31, 2011 reserves for insurance were adjusted (increased or decreased) by 10%, total costs and other deductions would change by $16.4 million, or .3%.

Fair Value of Assets Acquired and Liabilities Assumed. We have completed a number of acquisitions in recent years as discussed in Note 7 Fair Value Measurements in Part II, Item 8. Financial Statements and Supplementary Data. In conjunction with our accounting for these acquisitions, it was necessary for us to estimate the values of the assets acquired and liabilities assumed in the various business combinations using various assumptions. These estimates may be affected by such factors as changing market conditions, technological advances in the industry or changes in regulations governing the industry. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of property, plant and

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equipment, and the resulting amount of goodwill, if any. Unforeseen changes in operations or technology could substantially alter management s assumptions and could result in lower estimates of values of acquired assets or of future cash flows. This could result in impairment charges being recorded in our consolidated statements of income (loss). As the determination of the fair value of assets acquired and liabilities assumed is subject to significant management judgment and a change in purchase price allocations could result in a material difference in amounts recorded in our consolidated financial statements, management believes that accounting estimates related to the valuation of assets acquired and liabilities assumed are critical.

The determination of the fair value of assets and liabilities is based on the market for the assets and the settlement value of the liabilities. These estimates are made by management based on our experience with similar assets and liabilities. During 2011, 2010 and 2009, no significant changes were made to the methodology utilized to value assets acquired or liabilities assumed. Our estimates of the fair values of assets acquired and liabilities assumed have proved to be reliable in the past.

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

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

The assumptions used to estimate the fair market value of our stock options are based on historical and expected performance of our common shares in the open market, expectations with regard to the pattern with which our employees will exercise their options and the likelihood that dividends will be paid to holders of our common shares. During 2011, 2010 and 2009, no significant changes were made to the methodology utilized to determine the assumptions used in these calculations.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

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

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

At various times, we utilize local currency borrowings (foreign-currency-denominated debt), the payment structure of customer contracts and foreign exchange contracts to selectively hedge our exposure to exchange rate fluctuations in connection with monetary assets, liabilities, cash flows and commitments denominated in certain foreign currencies. A foreign exchange contract is a foreign currency transaction, defined as an agreement to exchange different currencies at a given future date and at a specified rate. A hypothetical 10% decrease in the value of all our foreign currencies relative to the U.S. dollar as of December 31, 2011 would result in a $11.1 million decrease in the fair value of our net monetary assets denominated in currencies other than U.S. dollars.

Credit Risk. Our financial instruments that potentially subject us to concentrations of credit risk consist primarily of cash equivalents, short-term and long-term investments, oil and gas financing receivables, accounts receivable and our range-cap-and-floor derivative instrument. Cash equivalents such as deposits and temporary cash investments are held by major banks or investment firms. Our short-term and long-term investments are managed within established guidelines that limit the amounts that may be invested with any one issuer and provide guidance as to issuer credit quality. We believe that the credit risk in our cash and investment portfolio is minimized as a result of the mix of our investments. In addition, our trade receivables are with a variety of U.S., international and foreign-country national oil and gas companies. Management considers this credit risk to be limited due to the financial resources of these companies. We perform ongoing credit evaluations of our customers, and we generally do not require material collateral. We do occasionally require prepayment of amounts from customers whose creditworthiness is in question prior to providing services to them. We maintain reserves for potential credit losses, and these losses historically have been within management s expectations.

Interest Rate, and Marketable and Non-marketable Security Price Risk. Our financial instruments that are potentially sensitive to changes in interest rates include our 5.375%, 6.15%, 9.25%, 5.0% and 4.625% senior notes, our range-cap-and-floor derivative instrument, our investments in debt securities (including corporate, asset-backed, mortgage-backed debt and mortgage-CMO debt securities) and our investments in overseas funds that invest primarily in a variety of public and private U.S. and non-U.S. securities (including asset-backed and mortgage-backed securities, global structured-asset securitizations, whole-loan mortgages, and participations in whole loans and whole-loan mortgages), which are classified as long-term investments.

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

On October 21, 2002, we entered into an interest rate swap transaction with a third-party financial institution to hedge our exposure to changes in the fair value of $200 million of our fixed rate 5.375% senior notes due 2012, which has been designated as a fair value hedge. Additionally on that date, we purchased a LIBOR range-cap and sold a LIBOR floor, in the form of a cashless collar, with the same third-party financial institution to help mitigate and manage our exposure to changes in the three-month U.S. dollar LIBOR rate. This transaction does not qualify for hedge accounting treatment, and any change in the cumulative fair value of this transaction is reflected as a gain or loss in our consolidated statements of income (loss). In June 2004, we unwound $100 million of the $200 million range-cap-and-floor derivative instrument. During the fourth quarter of 2005, we unwound the interest rate swap resulting in a loss of $2.7 million, which has been deferred and will be recognized as an increase to interest expense over the remaining life of our 5.375% senior notes due 2012. During the year ended December 31, 2005, we recorded interest savings of $2.7 million related to our interest rate swap agreement accounted for as a fair value hedge, which served to reduce interest expense.

The fair value of our range-cap-and-floor transaction is recorded as a derivative liability and included in other long-term liabilities. It totaled approximately $1.3 million and $3.4 million as of December 31, 2011 and 2010, respectively. During 2011, 2010 and 2009, we recorded gains (losses) of approximately $2.2 million, $(.1)

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million and $1.4 million, respectively, related to this derivative instrument; these amounts are included in losses (gains) on sales and retirements of long-lived assets and other expense (income), net in our consolidated statements of income (loss).

A hypothetical 10% adverse shift in quoted interest rates as of December 31, 2011 would decrease the fair value of our range-cap-and-floor derivative instrument by approximately $.1 million.

Fair Value of Financial Instruments. We estimate the fair value of our financial instruments in accordance with the provisions of the Fair Value Measurements and Disclosures Topic of the ASC. The fair value of our fixed rate long-term debt and subsidiary preferred stock is estimated based on quoted market prices or prices quoted from third-party financial institutions. The carrying and fair values of these liabilities were as follows:

	December 31,					
	2011			2010		
	Effective Interest Rate	Carrying Value	Fair Value	Effective Interest Rate	Carrying Value	Fair Value
	(In thousands, except interest rates)					
5.375% senior notes due August 2012(1)	5.61%	$ 274,604	$ 281,188	5.61%	$ 273,977	$ 291,500
6.15% senior notes due February 2018	6.42%	967,490	1,113,986	6.42%	966,276	1,041,008
9.25% senior notes due January 2019	9.33%	1,125,000	1,419,514	9.33%	1,125,000	1,393,943
5.00% senior notes due September 2020	5.20%	697,343	734,475	5.20%	697,037	678,335
4.625% senior notes due September 2021	4.75%	697,667	708,176			
0.94% senior exchangeable notes due May 2011				6.13%	1,378,178	1,403,315
Subsidiary preferred stock	4.0%	69,188	68,625	4.0%	69,188	68,625
Revolving credit facilities	2.35%	860,000	860,000			
Other		1,712	1,712		2,676	2,676
		$ 4,693,004	$ 5,187,676		$ 4,512,332	$ 4,879,402

(1) Includes $.3 million and $.7 million as of December 31, 2011 and 2010, respectively, related to the unamortized loss on the interest rate swap that was unwound during the fourth quarter of 2005.

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The fair values of our cash equivalents, trade receivables and trade payables approximate their carrying values due to the short-term nature of these instruments. Our cash, cash equivalents, short-term and long-term investments and other receivables are included in the table below:

	December 31, 2011			December 31, 2010		
	Fair Value	Interest Rates	Weighted-Average Life (Years)	Fair Value	Interest Rates	Weighted-Average Life (Years)
	(In thousands, except interest rates)					
Cash and cash equivalents	$ 398,575	0 - .21%	0.00	$ 641,702	0 - .28%	0.00
Short-term investments:						
Trading equity securities	11,600			19,630		
Available-for-sale equity securities	71,433			79,698		
Available-for-sale debt securities:						
Commercial paper and CDs	1,230	1.0%	.6	1,275	.75%	.6
Corporate debt securities	51,300	10.01 - 13.98%	2.5	52,022	10.01 - 13.99%	3.6
Mortgage-backed debt securities	309	2.4%	1.7	372	2.79%	2.7
Mortgage-CMO debt securities	2,547	.44 - 5.9%	.2	3,015	.42 - 5.9%	.3
Asset-backed debt securities	2,495	.78 - 4.8%	.8	3,476	.56 - 4.81%	1.3
Total available-for-sale debt securities	57,881			60,160		
Total available-for-sale securities	129,314			139,858		
Total short-term investments	140,914			159,488		
Long-term investments and other receivables:						
Actively managed funds	5,941	N/A		7,427	N/A	
Oil and gas financing receivables	5,183	13.10%		32,873	13.10 -13.52%	
Total long-term investments and other receivables	11,124			40,300		
Total cash, cash equivalents, short-term and long-term investments and other receivables	$ 550,613			$ 841,490		

Our investments in debt securities listed in the above table and a portion of our long-term investments are sensitive to changes in interest rates. Additionally, our investment portfolio of debt and equity securities, which are carried at fair value, exposes us to price risk. A hypothetical 10% decrease in the market prices for all securities as of December 31, 2011 would decrease the fair value of our trading securities and available-for-sale securities by $1.2 million and $12.9 million, respectively.

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ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders

of Nabors Industries Ltd.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income (loss), changes in equity and cash flows present fairly, in all material respects, the financial position of Nabors Industries Ltd. and its subsidiaries (the Company) at December 31, 2011 and December 31, 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which their oil and gas reserves are estimated as well as the manner in which prices are determined to calculate the ceiling limit on capitalized oil and gas costs as of December 31, 2009.

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

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 29, 2012

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(In thousands, except per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 398,575	$ 641,702
Short-term investments	140,914	159,488
Assets held for sale	401,500	352,048
Accounts receivable, net	1,576,555	1,116,510
Inventory	272,852	158,836
Deferred income taxes	127,874	31,510
Other current assets	170,044	152,836
Total current assets	3,088,314	2,612,930
Long-term investments and other receivables	11,124	40,300
Property, plant and equipment, net	8,629,946	7,815,419
Goodwill	501,258	494,372
Investment in unconsolidated affiliates	371,021	267,723
Other long-term assets	310,477	415,825
Total assets	$ 12,912,140	$ 11,646,569
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 275,326	$ 1,379,018
Trade accounts payable	782,753	355,282
Accrued liabilities	716,773	394,292
Income taxes payable	27,710	25,788
Total current liabilities	1,802,562	2,154,380
Long-term debt	4,348,490	3,064,126
Other long-term liabilities	292,758	245,765
Deferred income taxes	797,925	770,247
Total liabilities	7,241,735	6,234,518
Commitments and contingencies (Note 18)		
Subsidiary preferred stock (Notes 5 and 15)	69,188	69,188
Equity:		
Shareholders equity:		
Common shares, par value $.001 per share:		
Authorized common shares 800,000; issued 317,042 and 315,034, respectively	317	315
Capital in excess of par value	2,287,743	2,255,787
Accumulated other comprehensive income	321,264	342,052
Retained earnings	3,956,364	3,707,881
Less: treasury shares, at cost, 29,414 common shares	(977,873)	(977,873)

Total shareholders equity	5,587,815	5,328,162
Noncontrolling interest	13,402	14,701
Total equity	5,601,217	5,342,863
Total liabilities and equity	$ 12,912,140	$ 11,646,569

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

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except per share amounts)		
Revenues and other income:			
Operating revenues	$ 6,060,351	$ 4,134,483	$ 3,662,220
Earnings (losses) from unconsolidated affiliates	56,647	33,267	(155,432)
Investment income (loss)	19,940	7,263	25,522
Total revenues and other income	6,136,938	4,175,013	3,532,310
Costs and other deductions:			
Direct costs	3, 775,964	2,400,519	1,981,504
General and administrative expenses	489,892	338,720	421,492
Depreciation and amortization	924,094	760,962	663,958
Interest expense	256,633	272,712	266,047
Losses (gains) on sales and retirements of long-lived assets and other expense (income), net	4,514	47,238	11,982
Impairments and other charges	198,072	61,292	118,543
Total costs and other deductions	5,649,169	3,881,443	3,463,526
Income (loss) from continuing operations before income taxes	487,769	293,570	68,784
Income tax expense (benefit):			
Current	109,702	(77,209)	71,458
Deferred	32,903	114,159	(135,395)
Total income tax expense (benefit)	142,605	36,950	(63,937)
Subsidiary preferred stock dividend	3,000	750	
Income (loss) from continuing operations, net of tax	342,164	255,870	132,721
Income (loss) from discontinued operations, net of tax	(97,440)	(161,090)	(218,609)
Net income (loss)	244,724	94,780	(85,888)
Less: Net (income) loss attributable to noncontrolling interest	(1,045)	(85)	342
Net income (loss) attributable to Nabors	$ 243,679	$ 94,695	$ (85,546)
Earnings (losses) per share:			
Basic from continuing operations	$ 1.19	$ .90	$ .47
Basic from discontinued operations	(.34)	(.57)	(.77)
Total Basic	$ .85	$ .33	$ (.30)
Diluted from continuing operations	$ 1.17	$ .88	$ .46
Diluted from discontinued operations	(.34)	(.55)	(.76)

Total Diluted	$	.83	$	.33	$	(.30)
Weighted-average number of common shares outstanding:						
Basic		287,118		285,145		283,326
Diluted		292,484		289,996		286,502

The details of credit-related impairments to investments is presented below:

Other-than-temporary impairment on debt security	$	$	$ 40,300
Less: other-than-temporary impairment recognized in accumulated other comprehensive income (loss)			(4,651)
Credit-related impairment on investment(1)	$	$	$ 35,649

(1) Included in Impairments and other charges (Note 3)

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

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Cash flows from operating activities:			
Net income (loss) attributable to Nabors	$ 243,679	$ 94,695	$ (85,546)
Adjustments to net income (loss):			
Depreciation and amortization	927,460	766,519	668,415
Depletion and other exploratory expenses	44,551	27,002	11,078
Deferred income tax expense (benefit)	(34,739)	55,964	(218,760)
Deferred financing costs amortization	5,107	5,431	6,133
Pension liability amortization and adjustments	818	664	844
Discount amortization on long-term debt	27,042	70,719	86,802
Amortization of loss on hedges	927	786	580
Impairments and other charges	460,971	260,931	339,129
Losses (gains) on long-lived assets, net	(51,945)	(1,050)	12,339
Losses (gains) on investments, net	(12,486)	191	(9,954)
Losses (gains) on debt retirement, net	58	7,042	(11,197)
Losses (gains) on derivative instruments	234	2,471	338
Gain on acquisition	(13,114)		
Share-based compensation	21,244	13,746	106,725
Foreign currency transaction losses (gains), net	5,725	17,880	8,372
Equity in (earnings) losses of unconsolidated affiliates, net of dividends	(132,388)	(13,630)	229,813
Changes in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable	(459,455)	(249,725)	450,530
Inventory	(114,896)	(15,201)	52,995
Other current assets	(24,820)	6,589	205,108
Other long-term assets	71,867	7,509	(22,233)
Trade accounts payable and accrued liabilities	517,615	70,463	(146,470)
Income taxes payable	999	(19,208)	(62,535)
Other long-term liabilities	(27,967)	(2,804)	(5,534)
Net cash provided by operating activities	1,456,487	1,106,984	1,616,972
Cash flows from investing activities:			
Purchases of investments	(11,746)	(34,147)	(32,674)
Sales and maturities of investments	39,063	34,613	57,033
Cash paid for acquisition of businesses, net	(55,459)	(733,630)	
Investment in unconsolidated affiliates	(112,262)	(40,936)	(125,076)
Distribution of proceeds from asset sales of unconsolidated affiliates	142,984		
Capital expenditures	(2,042,617)	(930,277)	(1,093,435)
Proceeds from sales of assets and insurance claims	180,558	31,072	31,375
Net cash used for investing activities	(1,859,479)	(1,673,305)	(1,162,777)
Cash flows from financing activities:			
Increase (decrease) in cash overdrafts	6,375	(6,298)	(18,157)
Proceeds from issuance of long-term debt	697,578	696,948	1,124,978
Debt issuance costs	(7,141)	(8,934)	(8,832)
Payments for (proceeds from) hedge transactions		(5,667)	
Proceeds from revolving credit facilities	1,560,000	600,000	
Proceeds from issuance of common shares	11,605	8,201	11,249
Reduction in long-term debt	(1,404,281)	(398,514)	(1,081,801)
Reduction in revolving credit facilities	(700,000)	(600,000)	
Repurchase of equity component of convertible debt	(12)	(4,712)	(6,586)

Settlement of call options and warrants, net		1,134	
Purchase of restricted stock	(2,626)	(1,935)	(1,515)
Tax benefit related to share-based awards	1,747	31	37
Net cash provided by financing activities	163,245	280,254	19,373
Effect of exchange rate changes on cash and cash equivalents	(3,380)	(46)	12,160
Net increase (decrease) in cash and cash equivalents	(243,127)	(286,113)	485,728
Cash and cash equivalents, beginning of period	641,702	927,815	442,087
Cash and cash equivalents, end of period	$ 398,575	$ 641,702	$ 927,815

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

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

		Common Shares							
		Shares	Par Value	Capital in Excess of Par Value	Accumulated Other Comprehensive Income	Retained Earnings	Treasury Shares	Non-controlling Interest	Total Equity
					(In thousands)				
Balances, December 31, 2008		312,343	$ 312	$ 2,129,415	$ 53,520	$ 3,698,732	$ (977,873)	$ 14,318	$ 4,918,424
Comprehensive income (loss):									
Net income (loss) attributable to Nabors	$ (85,546)					(85,546)			(85,546)
Translation adjustment attributable to Nabors	150,290				150,290				150,290
Unrealized gains/(losses) on marketable securities, net of income benefit of $839	36,727				36,727				36,727
Unrealized gains/(losses) on adjusted basis for marketable debt security, net of income taxes of $1,199	1,956				1,956				1,956
Less: Reclassification adjustment for (gains)/losses included in net income (loss), net of income tax benefit of $4,921	49,386				49,386				49,386
Pension liability amortization, net of income taxes of $325	519				519				519
Pension liability adjustment, net of income taxes of $89	130				130				130
Unrealized gains/(losses) and amortization of (gains)/losses on cash flow hedges, net of income tax benefit of $18	178				178				178
Comprehensive income (loss) attributable to Nabors	$ 153,640								
Net income (loss) attributable to noncontrolling interest	(342)							(342)	(342)
Translation adjustment attributable to noncontrolling interest	2,024							2,024	2,024
Comprehensive income (loss) attributable to noncontrolling interest	1,682								
Total comprehensive income (loss)	$ 155,322								
Issuance of common shares for stock options exercised, net of surrender of unexercised stock options		1,476	2	11,247					11,249
Nabors Exchangeco shares exchanged		105							
Share-based compensation				106,725					106,725

Other		(9)		(8,064)				(1,677)	(9,741)
Balances, December 31, 2009		313,915	$ 314	$ 2,239,323	$ 292,706	$ 3,613,186	$ (977,873)	$ 14,323	$ 5,181,979
Balances, December 31, 2009		313,915	$ 314	$ 2,239,323	$ 292,706	$ 3,613,186	$ (977,873)	$ 14,323	$ 5,181,979
Comprehensive income (loss):									
Net income (loss) attributable to Nabors	$ 94,695					94,695			94,695
Translation adjustment attributable to Nabors	60,897				60,897				60,897
Unrealized gains/(losses) on marketable securities, net of income taxes of $7,435	(7,157)				(7,157)				(7,157)
Less: Reclassification adjustment for (gains)/losses included in net income (loss), net of income taxes of $693	(1,001)				(1,001)				(1,001)
Pension liability amortization, net of income taxes of $259	405				405				405
Pension liability adjustment, net of income tax benefit of $405	(635)				(635)				(635)
Unrealized gains/(losses) and amortization of (gains)/losses on cash flow hedges, net of income tax benefit of $2,119	(3,163)				(3,163)				(3,163)
Comprehensive income (loss) attributable to Nabors	$ 144,041								
Net income (loss) attributable to noncontrolling interest	85							85	85
Translation adjustment attributable to noncontrolling interest	723							723	723
Comprehensive income (loss) attributable to noncontrolling interest	808								
Total comprehensive income (loss)	$ 144,849								
Issuance of common shares for stock options exercised, net of surrender of unexercised stock options		714	1	8,200					8,201
Share-based compensation				13,746					13,746
Other		405		(5,482)				(430)	(5,912)
Balances, December 31, 2010		315,034	$ 315	$ 2,255,787	$ 342,052	$ 3,707,881	$ (977,873)	$ 14,701	$ 5,342,863

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

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NABORS INDUSTRIES LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (Continued)

		Common Shares		Capital in Excess of Par Value	Accumulated Other Comprehensive Income	Retained Earnings	Treasury Shares	Non-controlling Interest	Total Equity
		Shares	Par Value						
					(In thousands)				
Balances, December 31, 2010		315,034	$ 315	$ 2,255,787	$ 342,052	$ 3,707,881	$ (977,873)	$ 14,701	$ 5,342,863
Comprehensive income (loss):									
Net income (loss) attributable to Nabors	$ 243,679					243,679			243,679
Translation adjustment attributable to Nabors	(20,257)				(20,257)				(20,257)
Unrealized gains/(losses) on marketable securities, net of income taxes of $86	5,270				5,270				5,270
Less: Reclassification adjustment for (gains)/losses included in net income (loss), net of income taxes of $0	(3,036)				(3,036)				(3,036)
Pension liability amortization, net of income taxes of $319	499				499				499
Pension liability adjustment, net of income tax benefit of $2,421	(3,788)				(3,788)				(3,788)
Unrealized gains/(losses) and amortization of (gains)/losses on cash flow hedges, net of income tax benefit of $239	524				524				524
Comprehensive income (loss) attributable to Nabors	$ 222,891								
Net income (loss) attributable to noncontrolling interest	1,045							1,045	1,045
Translation adjustment attributable to noncontrolling interest	(185)							(185)	(185)
Comprehensive income (loss) attributable to noncontrolling interest	860								
Total comprehensive income (loss)	$ 223,751								
Issuance of common shares for stock options exercised, net of surrender of unexercised stock options		1,116	1	11,604					11,605
Share-based compensation				21,244					21,244
Other		892	1	(892)		4,804		(2,159)	1,754
Balances, December 31, 2011		317,042	$ 317	$ 2,287,743	$ 321,264	$ 3,956,364	$ (977,873)	$ 13,402	$ 5,601,217

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

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Note 1 Nature of Operations

Nabors is the largest land drilling contractor in the world and one of the largest land well-servicing and workover contractors in the United States and Canada:

- We actively market approximately 499 land drilling rigs for oil and gas land drilling operations in the U.S. Lower 48 states, Alaska, Canada, South America, Mexico, the Middle East, the Far East, the South Pacific, Russia and Africa.

- We actively market approximately 581 rigs for land well-servicing and workover work in the United States and approximately 174 rigs for land well-servicing and workover work in Canada.

We are also a leading provider of offshore platform workover and drilling rigs, and actively market 39 platform, 12 jackup and four barge rigs in the United States, including the Gulf of Mexico, and multiple international markets.

In addition to the foregoing services:

- We provide hydraulic fracturing, cementing, nitrogen and acid pressure pumping services with over 730,000 hydraulic horsepower in key basins throughout the United States and Canada.

- We offer a wide range of ancillary well-site services, including engineering, transportation and disposal, construction, maintenance, well logging, directional drilling, rig instrumentation, data collection and other support services in select U.S. and international markets.

- 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 have a 51% ownership interest in a joint venture in Saudi Arabia, which owns and actively markets nine rigs in addition to the rigs we lease to the joint venture.

- We have invested in oil and gas exploration, development and production activities through both our wholly owned subsidiaries and our oil and gas joint ventures in which we hold 49-50% ownership interests.

The majority of our business is conducted through our various Contract Drilling operating segments, which include our drilling, well-servicing, fluid logistics and workover operations, on land and offshore. Our hydraulic fracturing and downhole surveying services are included in our Pressure Pumping operating segment. Our oil and gas exploration, development and production operations are included in our Oil and Gas operating segment, or in discontinued operations in some cases. Our operating segments engaged in drilling technology and top drive manufacturing, directional drilling, rig instrumentation and software, and construction operations are aggregated in our Other Operating Segments.

The consolidated financial statements and related footnotes are presented in accordance with accounting principles generally accepted in the United States of America (GAAP). Certain reclassifications have been made to prior periods to conform to the current period presentation, with no effect on our consolidated financial position, results of operations or cash flows.

Note 2 Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of Nabors, as well as all majority owned and non-majority owned subsidiaries required to be consolidated under GAAP. Our consolidated financial statements

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exclude majority owned entities for which we do not have either (1) the ability to control the operating and financial decisions and policies of that entity or (2) a controlling financial interest in a variable interest entity. All significant intercompany accounts and transactions are eliminated in consolidation.

Investments in operating entities where we have the ability to exert significant influence, but where we do not control operating and financial policies, are accounted for using the equity method. Our share of the net income (loss) of these entities is recorded as earnings (losses) from unconsolidated affiliates in our consolidated statements of income (loss), and our investment in these entities is included as a single amount in our consolidated balance sheets. Investments in unconsolidated affiliates accounted for using the equity method totaled $371.0 million and $265.8 million as of December 31, 2011 and 2010, respectively. Investments in unconsolidated affiliates accounted for using the cost method totaled $1.9 million as of December 31, 2010. At December 31, 2011 and 2010, assets held for sale included investments in unconsolidated affiliates accounted for using the equity method totaling $13.7 million and $79.5 million, respectively. See Note 4 Discontinued Operations for additional information.

We have investments in offshore funds, which are classified as long-term investments and are accounted for using the equity method of accounting based on our ownership interest in each fund. The carrying value of these investments totaled $5.9 million and $7.4 million as of December 31, 2011 and 2010, respectively.

Cash and Cash Equivalents

Cash and cash equivalents include demand deposits and various other short-term investments with original maturities of three months or less.

Investments

Short-term investments

Short-term investments consist of equity securities, certificates of deposit, corporate debt securities, mortgage-backed debt securities and asset-backed debt securities. Securities classified as available-for-sale or trading are stated at fair value. Unrealized holding gains and temporary losses for available-for-sale securities are excluded from earnings and, until realized, are reported net of taxes in a separate component of equity. Unrealized holding losses are included in earnings during the period for which the loss is determined to be other-than-temporary. Gains and losses from changes in the market value of securities classified as trading are reported in earnings currently.

In computing realized gains and losses on the sale of equity securities, the specific-identification method is used. In accordance with this method, the cost of the equity securities sold is determined using the specific cost of the security when originally purchased.

Long-term investments and other receivables

We have investments in overseas funds that invest primarily in a variety of public and private U.S. and non-U.S. securities (including asset-backed and mortgage-backed securities, global structured-asset securitizations, whole-loan mortgages, and participations in whole loans and whole-loan mortgages). These investments are non-marketable and do not have published fair values. We account for these funds under the equity method of accounting based on our percentage ownership interest and recognize gains or losses as investment income (loss), currently based on changes in the net asset value of our investment during the current period.

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Our oil and gas financing receivables, previously included in long-term investments, have been reclassified to assets held for sale. These receivables represent our financing agreements for certain production payment contracts in our Oil and Gas segment.

Inventory

Inventory is stated at the lower of cost or market. Cost is determined using the first-in, first-out method and includes the cost of materials, labor and manufacturing overhead. Inventory included the following:

	December 31, 2011	December 31, 2010
	(In thousands)	
Raw materials	$ 133,480	$ 81,308
Work-in-progress	50,951	23,629
Finished goods	88,421	53,899
	$ 272,852	$ 158,836

Property, Plant and Equipment

Property, plant and equipment, including renewals and betterments, are stated at cost, while maintenance and repairs are expensed currently. Interest costs applicable to the construction of qualifying assets are capitalized as a component of the cost of such assets. We provide for the depreciation of our drilling and workover rigs using the units-of-production method. For each day a rig is operating, we depreciate it over an approximate 4,900-day period, with the exception of our jackup rigs which are depreciated over an 8,030-day period, after provision for salvage value. For each day a rig asset is not operating, it is depreciated over an assumed depreciable life of 20 years, with the exception of our jackup rigs, where a 30-year depreciable life is used, after provision for salvage value.

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

We review our assets for impairment annually or when events or changes in circumstances indicate that the carrying amounts of property, plant and equipment may not be recoverable. An impairment loss is recorded in the period in which it is determined that the sum of estimated future cash flows, on an undiscounted basis, is less than the carrying amount of the long-lived asset. Impairment charges are recorded using discounted cash flows which requires the estimation of dayrates and utilization, and such estimates can change based on market conditions, technological advances in the industry or changes in regulations governing the industry. Significant and unanticipated changes to the assumptions could result in future impairments. 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 impairment charges. As the determination of whether impairment charges should be recorded on our long-lived assets is subject to significant management judgment, and an impairment of these assets could result in a material charge on our consolidated statements of income (loss), management believes that accounting estimates related to impairment of long-lived assets are critical.

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Oil and Gas Properties

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 such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. However, these capitalized costs are subject to a ceiling test, which limits pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or market value of unproved properties. Future revenues for purposes of the ceiling test are valued using a 12-month average price, adjusted for the impact of derivatives accounted for as cash flow hedges as prescribed by the Securities and Exchange Commission (SEC) rules. During 2011 and 2009, our proportionate share of those ventures full-cost ceiling test writedowns was $15.6 million and $237.1 million, respectively. No full-cost ceiling test writedowns were recorded by our unconsolidated oil and gas joint ventures during 2010.

Our wholly owned oil and gas investment portfolio and our unconsolidated ownership interest in Remora is reflected in Assets held for sale in our consolidated balance sheet at December 31, 2011. We evaluate the carrying value of our assets held for sale to the fair value of the assets less costs to sale to determine whether impairment is indicated.

A significantly prolonged period of lower oil and natural gas prices or a reduction to the estimation of reserve quantities could continue to adversely affect the demand for and prices of our services, which could result in future impairment charges to our oil and gas properties.

Oil and Gas Reserves

Evaluations of oil and gas reserves are integral to making investment decisions about oil and gas properties such as whether development should proceed. Oil and gas reserve quantities are also used as the basis for calculating unit-of-production depreciation rates and for evaluating impairment. Oil and gas reserves include both proved and unproved reserves. Consistent with the definitions provided by the SEC, proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, known reservoirs, and under existing economic conditions. Unproved reserves are those with less than reasonable certainty of recoverability and include probable reserves. Probable reserves are reserves that are more likely to be recovered than not.

Estimation of proved reserves, which is based on the requirement of reasonable certainty, is an ongoing process involving rigorous technical evaluations, commercial and market assessment, and detailed analysis of well information such as flow rates and reservoir pressure declines. Although we are reasonably certain that proved reserves will be produced, the timing and amount recovered can be affected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and significant changes in long-term oil and gas price levels.

Goodwill

Goodwill represents the cost in excess of fair value of the net assets of companies acquired. We review goodwill and intangible assets with indefinite lives for impairment annually or more frequently if events or changes in circumstances indicate that the carrying amount of the reporting unit exceeds its fair value. All our operating segment s fair values were substantially in excess of their carrying value with the exception of the U.S. Land Well-servicing and International segments. These operating segments had an excess of fair value over carrying value of approximately 20%. As further discussed below in *Recent Accounting Pronouncements*, we

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changed the manner in which we initially assess goodwill for impairment during 2012. Under new guidance, we will assess qualitative factors to determine whether to perform the two-step quantitative goodwill impairment tests. 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 Note 3 Impairments and Other Charges for discussion of goodwill impairments.

The change in the carrying amount of goodwill for our various Contract Drilling segments, Pressure Pumping segment and Other Operating segments for the years ended December 31, 2011 and 2010 was as follows:

	Balance as of December 31, 2009	Acquisitions and Purchase Price Adjustments	Impairments	Cumulative Translation Adjustment	Balance as of December 31, 2010
			(In thousands)		
Contract Drilling:					
U.S. Lower 48 Land Drilling	$ 30,154	$	$	$	$ 30,154
U.S. Land Well-servicing	50,839	5,000(1)			55,839
U.S. Offshore	18,003		(10,707)(2)		7,296
Alaska	19,995				19,995
International	18,983				18,983
Subtotal Contract Drilling	137,974	5,000	(10,707)		132,267
Pressure Pumping		334,992(3)			334,992
Other Operating Segments	26,291			822	27,113
Total	$ 164,265	$ 339,992	$ (10,707)	$ 822	$ 494,372

	Balance as of December 31, 2010	Acquisitions and Purchase Price Adjustments	Impairments	Cumulative Translation Adjustment	Balance as of December 31, 2011
			(In thousands)		
Contract Drilling:					
U.S. Lower 48 Land Drilling	$ 30,154	$	$	$	$ 30,154
U.S. Land Well-servicing	55,839	(767)(1)			55,072
U.S. Offshore	7,296				7,296
Alaska	19,995				19,995
International	18,983				18,983
Subtotal Contract Drilling	132,267	(767)			131,500
Pressure Pumping	334,992				334,992

Other Operating Segments	27,113	8,000(4)		(347)	34,766
Total	$ 494,372	$ 7,233	$	$ (347)	$ 501,258

(1) Represents the goodwill recorded in connection with our acquisition of Energy Contractors during 2010 and an adjustment to the goodwill recorded during 2011. See Note 5 Acquisitions for additional discussion.

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(2) Represents goodwill impairment associated with our U.S. Offshore operating segment. The impairment charge was deemed necessary due to the uncertainty of utilization of some of our rigs as a result of changes in our customers plans for future drilling operations in the Gulf of Mexico. See Note 3 Impairments and Other Charges for additional information.

(3) Represents the goodwill recorded in connection with our acquisition of Superior. See Note 5 Acquisitions for additional discussion.

(4) Represents goodwill recorded in connection with our acquisition of the remaining 50 percent equity interest of Peak. See Note 5 Acquisitions for additional discussion.

Our Oil and Gas segment does not have any goodwill. Goodwill for the consolidated company, totaling approximately $12.9 million, is expected to be deductible for tax purposes.

Derivative Financial Instruments

We record derivative financial instruments (including certain derivative instruments embedded in other contracts) in our consolidated balance sheets at fair value as either assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. Accounting for derivatives qualifying as fair value hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of income. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured quarterly based on the relative cumulative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. Any change in fair value of derivative financial instruments that are speculative in nature and do not qualify for hedge accounting treatment is also recognized immediately in earnings. Proceeds received upon termination of derivative financial instruments qualifying as fair value hedges are deferred and amortized into income over the remaining life of the hedged item using the effective interest rate method.

Litigation and Insurance Reserves

We estimate our reserves related to litigation and insurance based on the facts and circumstances specific to the litigation and insurance claims and our past experience with similar claims. We maintain actuarially determined accruals in our consolidated balance sheets to cover self-insurance retentions. See Note 18 Commitments and Contingencies regarding self-insurance accruals. We estimate the range of our liability related to pending litigation when we believe the amount and range of loss can reasonably 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. For matters where an unfavorable outcome is reasonably possible and significant, we disclose the nature of the matter and a range of potential exposure, unless an estimate cannot be made at the time of disclosure.

Revenue Recognition

We recognize revenues and costs on daywork contracts daily as the work progresses. For certain contracts, we receive lump-sum payments for the mobilization of rigs and other drilling equipment. We defer revenue

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related to mobilization periods and recognize the revenue over the term of the related drilling contract. Costs incurred related to a mobilization period for which a contract is secured are deferred and recognized over the term of the related drilling contract. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. We defer recognition of revenue on amounts received from customers for prepayment of services until those services are provided.

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

In connection with the performance of our cementing services, we recognize product and service revenue when the products are delivered or services are provided to the customer and collectability is reasonably assured. Product sale prices are determined by published price lists provided to our customers.

We recognize, as operating revenue, proceeds from business interruption insurance claims in the period that the applicable proof of loss documentation is received. Proceeds from casualty insurance settlements in excess of the carrying value of damaged assets are recognized in losses (gains) on sales and retirements of long-lived assets and other expense (income), net in the period that the applicable proof of loss documentation is received. Proceeds from casualty insurance settlements that are expected to be less than the carrying value of damaged assets are recognized at the time the loss is incurred and recorded in losses (gains) on sales and retirements of long-lived assets and other expense (income), net.

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

We recognize revenue on our interests in oil and gas properties as production occurs and title passes. We apply the entitlement method of accounting for natural gas revenue. Under this method, revenues are recognized based on our revenue interest of production from our properties in which sales are disproportionately allocated to owners because of marketing or other contractual arrangements. Accordingly, revenue is not recognized for deliveries in excess of our net revenue interest, while revenue is recognized for any under delivered volumes. Production imbalances are generally recorded at estimated sales prices of the anticipated future settlements of the imbalances. Production volume is monitored to minimize these natural gas imbalances.

Share-Based Compensation

We record compensation expense for all share-based awards granted. The amount of compensation expense recognized is based on the grant-date fair value. See Note 8 Share-Based Compensation for additional discussion.

Income Taxes

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

We recognize increases to our tax reserves for uncertain tax positions along with interest and penalties as an increase to other long-term liabilities.

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

Nabors realizes an income tax benefit associated with certain awards issued under our stock plans. We recognize the benefits related to tax deductions up to the amount of the compensation expense recorded for the award in the consolidated statements of income (loss). Any excess tax benefit (i.e., tax deduction in excess of compensation expense) is reflected as an increase in capital in excess of par. Any shortfall is recorded as a reduction to capital in excess of par to the extent of our aggregate accumulated pool of windfall benefits, beyond which the shortfall would be recognized in the consolidated statements of income (loss).

Foreign Currency Translation

For certain of our foreign subsidiaries, such as those in Canada and Argentina, the local currency is the functional currency, and therefore translation gains or losses associated with foreign-denominated monetary accounts are accumulated in a separate section of the consolidated statements of changes in equity. For our other international subsidiaries, the U.S. dollar is the functional currency, and therefore local currency transaction gains and losses, arising from remeasurement of payables and receivables denominated in local currency, are included in our consolidated statements of income (loss).

Cash Flows

We treat the redemption price, including accrued original issue discount, on our convertible debt instruments as a financing activity for purposes of reporting cash flows in our consolidated statements of cash flows.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosures of contingent assets and liabilities at the balance sheet date and the amounts of revenues and expenses recognized during the reporting period. Actual results could differ from such estimates. Areas where critical accounting estimates are made by management include:

- financial instruments;
- depreciation of property, plant and equipment;
- impairment of long-lived assets;
- impairment of goodwill and intangible assets;
- impairment of oil and gas properties;

valuation of oil and gas reserves;

income taxes;

litigation and self-insurance reserves;

fair value of assets acquired and liabilities assumed; and

share-based compensation.

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Recent Accounting Pronouncements

In December 2008, the SEC issued a Final Rule, Modernization of Oil and Gas Reporting. This rule revised 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 Financial Accounting Standards Board (FASB) issued revised guidance that substantially aligned the oil and gas accounting disclosures with the SEC s Final Rule. The 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 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 were effective for registration statements filed on or after January 1, 2010 and for annual financial statements filed on or after December 31, 2009. 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 were considered with operating results from our unconsolidated oil and gas joint ventures, which we account for under the equity method of accounting, we had significant oil and gas activities under the new definition. Our oil and gas disclosures for the years ended December 31, 2011 and 2010 are provided in Note 24 Supplementary Information on Oil and Gas Exploration and Production Activit