HALLIBURTON CO
Form 10-K
February 17, 2011

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, 2010

OR

[ ] 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 001-03492

HALLIBURTON COMPANY
(Exact name of registrant as specified in its charter)

Delaware	75-2677995
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3000 North Sam Houston Parkway East
Houston, Texas 77032
(Address of principal executive offices)
Telephone Number – Area code (281) 871-2699

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

Title of each class	Name of each exchange on which registered
Common Stock par value $2.50 per share	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] 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 [X]

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 [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. [ ]

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

Large accelerated filer	[X]	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 [X]

The aggregate market value of Common Stock held by nonaffiliates on June 30, 2010, determined using the per share closing price on the New York Stock Exchange Composite tape of $24.55 on that date was approximately $22,217,000,000.

As of February 11, 2011, there were 913,356,387 shares of Halliburton Company Common Stock, $2.50 par value per share, outstanding.

Portions of the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 001-03492) are incorporated by reference into Part III of this report.

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For the Year Ended December 31, 2010

PART I

Item 1. Business.

General description of business

Halliburton Company's predecessor was established in 1919 and incorporated under the laws of the State of Delaware in 1924. We provide a variety of services and products to customers in the energy industry related to the exploration, development, and production of oil and natural gas. We serve major, national, and independent oil and natural gas companies throughout the world and operate under two divisions, which form the basis for the two operating segments we report: the Completion and Production segment and the Drilling and Evaluation segment. See Note 2 to the consolidated financial statements for further financial information related to each of our business segments and a description of the services and products provided by each segment.

Business strategy

Our business strategy is to secure a distinct and sustainable competitive position as an oilfield service company by delivering products and services to our customers that maximize their production and recovery and realize proven reserves from difficult environments. Our objectives are to:

- create a balanced portfolio of products and services supported by global infrastructure and anchored by technology innovation with a well-integrated digital strategy to further differentiate our company;
- reach a distinguished level of operational excellence that reduces costs and creates real value from everything we do;
- preserve a dynamic workforce by being a preferred employer to attract, develop, and retain the best global talent; and
- uphold the ethical and business standards of the company and maintain the highest standards of health, safety, and environmental performance.

Markets and competition

We are one of the world's largest diversified energy services companies. Our services and products are sold in highly competitive markets throughout the world. Competitive factors impacting sales of our services and products include:

- price;
- service delivery (including the ability to deliver services and products on an "as needed, where needed" basis);
- health, safety, and environmental standards and practices;
- service quality;
- global talent retention;
- understanding of the geological characteristics of the hydrocarbon reservoir;
- product quality;
- warranty; and
- technical proficiency.

We conduct business worldwide in approximately 80 countries. The business operations of our divisions are organized around four primary geographic regions: North America, Latin America, Europe/Africa/CIS, and Middle East/Asia. In 2010, based on the location of services provided and products sold, 46% of our consolidated revenue was from the United States. In 2009 and 2008, 36% and 43% of our consolidated revenue was from the United States. No other country accounted for more than 10% of our consolidated revenue during these periods. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Environment and Results of Operations" and Note 2 to the consolidated financial statements for additional financial information about geographic operations in the last three years. Because the markets for our services and products are vast and cross numerous geographic lines, a meaningful estimate of the total number of competitors cannot be made. The industries we serve are highly competitive, and we have many substantial competitors. Largely, all of our services and products are marketed through our servicing and sales organizations.

Operations in some countries may be adversely affected by unsettled political conditions, acts of terrorism, civil unrest, expropriation or other governmental actions, exchange control problems, and highly inflationary currencies. We believe the geographic diversification of our business activities reduces the risk that loss of operations in any one country would be material to the conduct of our operations taken as a whole.

Information regarding our exposure to foreign currency fluctuations, risk concentration, and financial instruments used to minimize risk is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Financial Instrument Market Risk" and in Note 12 to the consolidated financial statements.

Customers

Our revenue from continuing operations during the past three years was derived from the sale of services and products to the energy industry. No customer represented more than 10% of consolidated revenue in any period presented.

Raw materials

Raw materials essential to our business are normally readily available. Market conditions can trigger constraints in the supply of certain raw materials, such as sand, cement, and specialty metals. We are always seeking ways to ensure the availability of resources, as well as manage costs of raw materials. Our procurement department is using our size and buying power through several programs designed to ensure that we have access to key materials at competitive prices.

Research and development costs

We maintain an active research and development program. The program improves existing products and processes, develops new products and processes, and improves engineering standards and practices that serve the changing needs of our customers, such as those related to high pressure/high temperature environments. Our expenditures for research and development activities were $366 million in 2010, $325 million in 2009, and $326 million in 2008, of which over 96% was company-sponsored in each year.

Patents

We own a large number of patents and have pending a substantial number of patent applications covering various products and processes. We are also licensed to utilize patents owned by others. We do not consider any particular patent to be material to our business operations.

Seasonality

Weather and natural phenomena can temporarily affect the performance of our services, but the widespread geographical locations of our operations serve to mitigate those effects. Examples of how weather can impact our business include:

- the severity and duration of the winter in North America can have a significant impact on natural gas storage levels and drilling activity for natural gas;
- the timing and duration of the spring thaw in Canada directly affects activity levels due to road restrictions;
- typhoons and hurricanes can disrupt coastal and offshore operations; and
- severe weather during the winter months normally results in reduced activity levels in the North Sea and Russia.

In addition, due to higher spending near the end of the year by customers for software and completion tools and services, these operations are generally stronger in the fourth quarter of the year than at the beginning of the year.

Employees

At December 31, 2010, we employed approximately 58,000 people worldwide compared to approximately 51,000 at December 31, 2009. At December 31, 2010, approximately 18% of our employees were subject to collective bargaining agreements. Based upon the geographic diversification of these employees, we do not believe any risk of loss from employee strikes or other collective actions would be material to the conduct of our operations taken as a whole.

Environmental regulation

We are subject to numerous environmental, legal, and regulatory requirements related to our operations worldwide. For further information related to environmental matters and regulation, see Note 8 to the consolidated financial statements, Item 1(a), “Risk Factors,” and Item 3, “Legal Proceedings.”

Working capital

We fund our business operations through a combination of available cash and equivalents, short-term investments, and cash flow generated from operations. In addition, our revolving credit facility is available for additional working capital needs.

Web site access

Our annual reports 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 Exchange Act of 1934 are made available free of charge on our internet web site at www.halliburton.com as soon as reasonably practicable after we have electronically filed the material with, or furnished it to, the Securities and Exchange Commission (SEC). The public may read and copy any materials we have filed with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Room 1580, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains our reports, proxy and information statements, and our other SEC filings. The address of that site is www.sec.gov. We have posted on our web site our Code of Business Conduct, which applies to all of our employees and Directors and serves as a code of ethics for our principal executive officer, principal financial officer, principal accounting officer, and other persons performing similar functions. Any amendments to our Code of Business Conduct or any waivers from provisions of our Code of Business Conduct granted to the specified officers above are disclosed on our web site within four business days after the date of any amendment or waiver pertaining to these officers. There have been no waivers from provisions of our Code of Business Conduct for the years 2010, 2009, or 2008. Except to the extent expressly stated otherwise, information contained on or accessible from our web site or any other web site is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report.

Executive Officers of the Registrant

The following table indicates the names and ages of the executive officers of Halliburton Company as of February 11, 2011, including all offices and positions held by each in the past five years:

Name and Age	Offices Held and Term of Office
Joseph F. Andolino (Age 57)	Senior Vice President, Tax of Halliburton Company, since January 2011 Vice President, Business Development of Goodrich Corporation, January 2009 to December 2010 Vice President, Tax and Business Development of Goodrich Corporation, November 1999 to December 2008
Evelyn M. Angelle (Age 43)	Senior Vice President and Chief Accounting Officer of Halliburton Company, since January 2011 Vice President, Corporate Controller, and Principal Accounting Officer of Halliburton Company, January 2008 to January 2011 Vice President, Operations Finance of Halliburton Company, December 2007 to January 2008 Vice President, Investor Relations of Halliburton Company, April 2005 to November 2007
James S. Brown (Age 56)	President, Western Hemisphere of Halliburton Company, since January 2008 Senior Vice President, Western Hemisphere of Halliburton Company, June 2006 to December 2007 Senior Vice President, United States Region of Halliburton Company, December 2003 to June 2006
* Albert O. Cornelison, Jr. (Age 61)	Executive Vice President and General Counsel of Halliburton Company, since December 2002
* David J. Lesar (Age 57)	Chairman of the Board, President, and Chief Executive Officer of Halliburton Company, since August 2000
* Mark A. McCollum (Age 51)	Executive Vice President and Chief Financial Officer of Halliburton Company, since January 2008 Senior Vice President and Chief Accounting Officer of Halliburton Company, August 2003 to December 2007

Craig W. Nunez (Age 49)	Senior Vice President and Treasurer of Halliburton Company, since January 2007 Vice President and Treasurer of Halliburton Company, February 2006 to January 2007

Name and Age	Offices Held and Term of Office
Joe D. Rainey (Age 54)	President, Eastern Hemisphere of Halliburton Company, since January 2011 Senior Vice President, Eastern Hemisphere of Halliburton Company, January 2010 to December 2010 Vice President, Eurasia Pacific Region of Halliburton Company, January 2009 to December 2009 Vice President, Asia Pacific Region of Halliburton Company, February 2005 to December 2008
* Lawrence J. Pope (Age 42)	Executive Vice President of Administration and Chief Human Resources Officer of Halliburton Company, since January 2008 Vice President, Human Resources and Administration of Halliburton Company, January 2006 to December 2007
* Timothy J. Probert (Age 59)	President, Strategy and Corporate Development of Halliburton Company, since January 2011 President, Global Business Lines and Corporate Development of Halliburton Company, January 2010 to January 2011 President, Drilling and Evaluation Division and Corporate Development of Halliburton Company, March 2009 to December 2009 Executive Vice President, Strategy and Corporate Development of Halliburton Company, January 2008 to March 2009 Senior Vice President, Drilling and Evaluation of Halliburton Company, July 2007 to December 2007 Senior Vice President, Drilling and Evaluation and Digital Solutions of Halliburton Company, May 2006 to July 2007 Vice President, Drilling and Formation Evaluation of Halliburton Company, January 2003 to May 2006

* Members of the Policy Committee of the registrant.

There are no family relationships between the executive officers of the registrant or between any director and any executive officer of the registrant.

Item 1(a). Risk Factors.

The statements in this section describe the known material risks to our business and should be considered carefully.

We, among others, have been named as a defendant in numerous lawsuits and are the subject of numerous investigations relating to the Macondo well incident that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

The semisubmersible drilling rig, Deepwater Horizon, sank on April 22, 2010 after an explosion and fire onboard the rig that began on April 20, 2010. The Deepwater Horizon was owned by Transocean Ltd. and had been drilling the Macondo exploration well in Mississippi Canyon Block 252 in the Gulf of Mexico for BP Exploration & Production, Inc. (BP Exploration), the lease operator and indirect wholly owned subsidiary of BP p.l.c. (BP p.l.c., BP Exploration, and their affiliates, collectively, BP). There were eleven fatalities and a number of injuries as a result of the Macondo well incident. Crude oil escaping from the Macondo well site spread across thousands of square miles of the Gulf of Mexico and reached the United States Gulf Coast. We performed a variety of services for BP Exploration, including cementing, mud logging, directional drilling, measurement-while-drilling, and rig data acquisition services.

To date, we have been named along with other unaffiliated defendants in more than 330 complaints, most of which are alleged class-actions, involving pollution damage claims and at least 28 personal injury lawsuits involving six decedents and 54 allegedly injured persons who were on the drilling rig at the time of the incident. Another six lawsuits naming us and others relate to alleged personal injuries sustained by those responding to the explosion and oil spill. Additional lawsuits may be filed against us, including criminal and civil charges under federal and state statutes and regulations. Those statutes and regulations could result in criminal penalties, including fines and imprisonment, as well as civil fines, and the degree of the penalties and fines may depend on the type of conduct and level of culpability, including strict liability, negligence, gross negligence, and knowing violations of the statute or regulation.

In addition to the claims and lawsuits described above, numerous industry participants, governmental agencies and Congressional committees are investigating or plan to investigate the cause of the explosion, fire, and resulting oil spill. According to the January 11, 2011 report (Investigation Report) of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission), the "immediate causes" of the incident were the result of a series of missteps, oversights, miscommunications and failures to appreciate risk by BP, Transocean, and us, although the National Commission acknowledged that there were still many things it did not know about the incident, such as the role of the blowout preventer. The National Commission also acknowledged that it may never know the extent to which each mistake or oversight caused the Macondo well incident, but concluded that the immediate cause was "a failure to contain hydrocarbon pressures in the well," and pointed to three things that could have contained those pressures: "the cement at the bottom of the well, the mud in the well and in the riser, and the blowout preventer." In addition, the Investigation Report states that "primary cement failure was a direct cause of the blowout" and that cement testing performed by an independent laboratory "strongly suggests" that the foam cement slurry used on the Macondo well was unstable. The Investigation Report also identified the failure of BP's and our processes for cement testing and communication failures among BP, Transocean, and us with respect to the difficulty of the cement job as examples of systemic failures by industry management.

Our contract with BP Exploration relating to the Macondo well provides for our indemnification for claims and expenses relating to the Macondo well incident. Given the potential amounts involved, BP Exploration and other indemnifying parties may seek to avoid their indemnification obligations. Indemnification for criminal fines or penalties, if any, may not be available if a court were to find such indemnification unenforceable as against public policy. In addition, we believe the law likely to be held applicable to matters relating to the Macondo well incident does not allow for enforcement of indemnification of persons who are found to be grossly negligent. Certain state laws, if deemed to apply, also would not allow for enforcement of indemnification for gross negligence, and may not allow for enforcement of indemnification of persons who are found to be negligent with respect to personal injury claims. In addition, financial analysts and the press have speculated about the financial capacity of BP, and whether it might seek to avoid indemnification obligations in bankruptcy proceedings. If BP Exploration filed for bankruptcy protection, a bankruptcy judge could disallow our contract with BP Exploration, including the indemnification obligations thereunder. Also, we may not be insured with respect to civil or criminal fines or penalties, if any, pursuant to the terms of our insurance policies.

As of December 31, 2010, we had not accrued any amounts related to this matter because we do not believe that a loss is probable. We are currently unable to estimate the full impact the Macondo well incident will have on us. Further, an estimate of possible loss or range of loss related to this matter cannot be made. However, considering the complexity of the Macondo well and the number of investigations being conducted and lawsuits pending, new information or future developments may require us to adjust our liability assessment. If proceedings and investigations are not resolved in our favor, resulting liabilities, fines, or penalties, if any, for which we are not indemnified or are not insured could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Certain matters relating to the Macondo well incident, including increased regulation of the United States offshore drilling industry, and similar catastrophic events could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Results of the Macondo well incident and the subsequent oil spill have included offshore drilling delays and increased federal regulation of our and our customers' operations, and more delays and regulations are expected. For example, the Investigation Report recommended, among other things, a review of and numerous changes to drilling and environmental regulations and the creation of new, independent agencies to oversee the various aspects of offshore drilling. The Bureau of Ocean Energy Management, Regulation and Enforcement (BOE) recently announced the creation of two new agencies and had previously issued guidance and regulations for drillers that intend to resume deepwater drilling activity. The BOE's regulations focus in part on increased safety and environmental issues, drilling equipment, and the requirement that operators submit drilling applications demonstrating regulatory compliance with respect to, among other things, required independent third-party inspections, certification of well design and well control equipment and emergency response plans in the event of a blowout.

Any increased regulation of the exploration and production industry as a whole that arises out of the Macondo well incident could result in higher operating costs for our customers, extended permitting and drilling delays, and reduced demand for our services. We cannot predict to what extent increased regulation may be adopted in international or other jurisdictions or whether we and our customers will be required or may elect to implement responsive policies and procedures in jurisdictions where they may not be required.

In addition, the Macondo well incident has negatively impacted and could continue to negatively impact the availability and cost of insurance coverage for our customers and their service providers. Also, our relationships with BP and others involved in the Macondo well incident could be negatively affected. Our business may be adversely impacted by any negative publicity relating to the incident, any negative perceptions about us by our customers, any increases in insurance premiums or difficulty in obtaining coverage, and the diversion of management's attention from our operations to focus on matters relating to the incident.

As illustrated by the Macondo well incident, the services we provide for our customers are performed in challenging environments which can be dangerous. Catastrophic events such as a well blowout, fire or explosion can occur, resulting in property damage, personal injury, death, pollution, and environmental damage. While we are typically indemnified by our customers for these types of events and the resulting damages and injuries (except in some cases, claims by our employees, loss or damage to our property, and any pollution emanating directly from our equipment), we will be exposed to significant potential losses should such catastrophic events occur if adequate indemnification provisions or insurance arrangements are not in place, if existing indemnity provisions are determined by a court to be unenforceable, or if our customer is unable or unwilling to satisfy its indemnity obligation.

The matters discussed above relating to the Macondo well incident and similar catastrophic events could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We could be subject to claims under our indemnification in favor of KBR for liability with respect to undersea bolts installed in connection with KBR's Barracuda-Caratinga project that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We provided indemnification in favor of KBR, Inc. (KBR) for out-of-pocket cash costs and expenses, or cash settlements or cash arbitration awards, KBR may incur as a result of the replacement of certain subsea flowline bolts installed in connection with KBR's Barracuda-Caratinga project.

At the direction of Petrobras, the Brazilian national oil company, KBR replaced certain bolts located on the subsea flowlines that failed through mid-November 2005, and KBR has informed us that additional bolts have failed thereafter, which were replaced by Petrobras. In March 2006, Petrobras commenced arbitration against KBR claiming $220 million plus interest for the cost of monitoring and replacing the defective bolts and all related costs and expenses of the arbitration, including the cost of attorneys' fees. The parties presented evidence and witnesses to the arbitration panel in May 2010, and final arguments were presented in August 2010. An adverse determination or result against KBR in the arbitration could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Our operations are subject to political and economic instability and risk of government actions that could have a material adverse effect on our consolidated results of operations and consolidated financial condition.

We are exposed to risks inherent in doing business in each of the countries in which we operate. Our operations are subject to various risks unique to each country that could have a material adverse effect on our consolidated results of operations and consolidated financial condition. With respect to any particular country, these risks may include:

- political and economic instability, including:
  - civil unrest, acts of terrorism, force majeure, war, or other armed conflict;
  - inflation; and
  - currency fluctuations, devaluations, and conversion restrictions;
- governmental actions that may:
  - result in expropriation and nationalization of our assets in that country;
  - result in confiscatory taxation or other adverse tax policies;
  - limit or disrupt markets, restrict payments, or limit the movement of funds;
  - result in the deprivation of contract rights; and
  - result in the inability to obtain or retain licenses required for operation.

For example, due to the unsettled political conditions in many oil-producing countries, our revenue and profits are subject to the adverse consequences of war, the effects of terrorism, civil unrest, strikes, currency controls, and governmental actions. Countries where we operate that have significant political risk include, but are not limited to: Algeria, Egypt, Indonesia, Iraq, Nigeria, Mexico, Russia, Azerbaijan, Kazakhstan, and Venezuela. Our facilities and our employees are under threat of attack in some countries where we operate. In addition, military action or continued unrest in the Middle East could impact the supply and pricing for oil and natural gas, disrupt our operations in the region and elsewhere, and increase our costs for security worldwide.

Our operations outside the United States require us to comply with a number of United States and international regulations, violations of which could have a material adverse effect on our consolidated results of operations and consolidated financial condition.

Our operations outside the United States require us to comply with a number of United States and international regulations. For example, our operations in countries outside the United States are subject to the Foreign Corrupt Practices Act (FCPA), which prohibits United States companies or their agents and employees from providing anything of value to a foreign official for the purposes of influencing any act or decision of these individuals in their official capacity to help obtain or retain business, direct business to any person or corporate entity, or obtain any unfair advantage. Our activities create the risk of unauthorized payments or offers of payments by one of our employees, agents, or joint venture partners that could be in violation of the FCPA, even though these parties are not always subject to our control. We have internal control policies and procedures and have implemented training and compliance programs for our employees and agents with respect to the FCPA. However, we cannot assure that our policies, procedures and programs always will protect us from reckless or criminal acts committed by our employees or agents. Allegations of violations of applicable anti-corruption laws, including the FCPA, may result in internal, independent, or government investigations. Violations of the FCPA may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could have a material adverse effect on our business, consolidated results of operations and consolidated financial condition. In addition, investigations by governmental authorities as well as legal, social, economic, and political issues in these countries could have a material adverse effect on our business and consolidated results of operations. We are also subject to the risks that our employees, joint venture partners, and agents outside of the United States may fail to comply with other applicable laws.

Acts of terrorism and threats of armed conflicts in or around various areas in which we operate could limit or disrupt markets and our operations, including disruptions resulting from the evacuation of personnel, cancellation of contracts, or the loss of personnel or assets.

Acts of terrorism and threats of armed conflicts in or around various areas in which we operate, such as the Middle East/North Africa, Mexico, Russia, Azerbaijan, Kazakhstan, Nigeria, and Indonesia, could limit or disrupt markets and our operations, including disruptions resulting from the evacuation of personnel, cancellation of contracts, or the loss of personnel or assets. Such events may cause further disruption to financial and commercial markets and may generate greater political and economic instability in some of the geographic areas in which we operate. In addition, any possible reprisals as a consequence of the wars and ongoing military action in the Middle East, such as acts of terrorism in the United States or elsewhere, could have a material adverse effect on our business and consolidated results of operations.

Changes in or interpretation of tax law and currency/repatriation control could impact the determination of our income tax liabilities for a tax year.

We have operations in approximately 80 countries other than the United States. Consequently, we are subject to the jurisdiction of a significant number of taxing authorities. The income earned in these various jurisdictions is taxed on differing bases, including net income actually earned, net income deemed earned, and revenue-based tax withholding. The final determination of our income tax liabilities involves the interpretation of local tax laws, tax treaties, and related authorities in each jurisdiction, as well as the significant use of estimates and assumptions regarding the scope of future operations and results achieved and the timing and nature of income earned and expenditures incurred. Changes in the operating environment, including changes in or interpretation of tax law and currency/repatriation controls, could impact the determination of our income tax liabilities for a tax year.

We are subject to foreign exchange risks and limitations on our ability to reinvest earnings from operations in one country to fund the capital needs of our operations in other countries or to repatriate assets from some countries.

A sizable portion of our consolidated revenue and consolidated operating expenses is in foreign currencies. As a result, we are subject to significant risks, including:

- foreign exchange risks resulting from changes in foreign exchange rates and the implementation of exchange controls; and
- limitations on our ability to reinvest earnings from operations in one country to fund the capital needs of our operations in other countries.

As an example, we conduct business in countries, such as Venezuela, that have nontraded or “soft” currencies that, because of their restricted or limited trading markets, may be more difficult to exchange for “hard” currency. We may accumulate cash in soft currencies, and we may be limited in our ability to convert our profits into United States dollars or to repatriate the profits from those countries.

Trends in oil and natural gas prices affect the level of exploration, development and production activity of our customers and the demand for our services and products which could have a material adverse effect on our consolidated results of operations and consolidated financial condition.

Demand for our services and products is particularly sensitive to the level of exploration, development, and production activity of, and the corresponding capital spending by, oil and natural gas companies, including national oil companies. The level of exploration, development, and production activity is directly affected by trends in oil and natural gas prices, which, historically, have been volatile and are likely to continue to be volatile.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of other economic factors that are beyond our control. Any prolonged reduction in oil and natural gas prices will depress the immediate levels of exploration, development, and production activity which could have a material adverse effect on our consolidated results of operations and consolidated financial condition. Even the perception of longer-term lower oil and natural gas prices by oil and natural gas companies can similarly reduce or defer major expenditures given the long-term nature of many large-scale development projects. Factors affecting the prices of oil and natural gas include:

- governmental regulations, including the policies of governments regarding the exploration for and production and development of their oil and natural gas reserves;
- global weather conditions and natural disasters;
- worldwide political, military, and economic conditions;
- the level of oil production by non-OPEC countries and the available excess production capacity within OPEC;
- oil refining capacity and shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
- the cost of producing and delivering oil and natural gas;
- potential acceleration of development of alternative fuels; and
- the level of supply and demand for oil and natural gas, especially demand for natural gas in the United States.

Our business is dependent on capital spending by our customers and reductions in capital spending could have a material adverse effect on our consolidated results of operations.

Our business is directly affected by changes in capital expenditures by our customers, and restrictions in capital spending could have a material adverse effect on our consolidated results of operations. Some of the changes that may materially and adversely affect us include:

- the consolidation of our customers, which could:
  - cause customers to reduce their capital spending, which would in turn reduce the demand for our services and products; and
  - result in customer personnel changes, which in turn affect the timing of contract negotiations;
- adverse developments in the business and operations of our customers in the oil and natural gas industry, including write-downs of reserves and reductions in capital spending for exploration, development, and production; and
- ability of our customers to timely pay the amounts due us.

If our customers delay in paying or fail to pay a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We depend on a limited number of significant customers. While none of these customers represented more than 10% of consolidated revenue in any period presented, the loss of one or more significant customers could have a material adverse effect on our business and our consolidated results of operations.

In most cases, we bill our customers for our services in arrears and are, therefore, subject to our customers delaying or failing to pay our invoices. In weak economic environments, we may experience increased delays and failures due to, among other reasons, a reduction in our customers' cash flow from operations and their access to the credit markets. If our customers delay in paying or fail to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Our business in Venezuela subjects us to actions by the Venezuelan government and delays in receiving payments, which could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We believe there are risks associated with our operations in Venezuela, including the possibility that the Venezuelan government could assume control over our operations and assets. We also continue to see a delay in receiving payment on our receivables from our primary customer in Venezuela. If our customer further delays in paying or fails to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

The future results of our Venezuelan operations will be affected by many factors, including our ability to take actions to mitigate the effect of a devaluation of the Bolívar Fuerte, the foreign currency exchange rate, actions of the Venezuelan government, and general economic conditions such as continued inflation and future customer payments and spending.

Doing business with national oil companies exposes us to greater risks of cost overruns, delays, and project losses and unsettled political conditions that can heighten these risks.

Much of the world's oil and natural gas reserves are controlled by national or state-owned oil companies (NOCs). Several of the NOCs are among our top 20 customers. Increasingly, NOCs are turning to oilfield services companies like us to provide the services, technologies, and expertise needed to develop their reserves. Reserve estimation is a subjective process that involves estimating location and volumes based on a variety of assumptions and variables that cannot be directly measured. As such, the NOCs may provide us with inaccurate information in relation to their reserves that may result in cost overruns, delays, and project losses. In addition, NOCs often operate in countries with unsettled political conditions, war, civil unrest, or other types of community issues. These types of issues may also result in similar cost overruns, losses, and contract delays.

A downward trend in estimates of production volumes or commodity prices or an upward trend in production costs could have a material adverse effect on our consolidated results of operations and result in impairment of or higher depletion rate on our oil and natural gas properties.

We have interests in oil and natural gas properties primarily in North America totaling approximately $136 million, net of accumulated depletion, which we account for under the successful efforts method. These oil and natural gas properties are assessed for impairment whenever changes in facts and circumstances indicate that the properties' carrying amounts may not be recoverable. The expected future cash flows used for impairment reviews and related fair-value calculations are based on judgmental assessments of future production volumes, prices, and costs, considering all available information at the date of review.

A downward trend in estimates of production volumes or prices or an upward trend in production costs could have a material adverse effect on our consolidated results of operations and result in other impairment charges or a higher depletion rate on our oil and natural gas properties.

Some of our customers require us to enter into long-term, fixed-price contracts that may require us to assume additional risks associated with cost over-runs, operating cost inflation, labor availability and productivity, supplier and contractor pricing and performance, and potential claims for liquidated damages.

Our customers, primarily NOCs, may require integrated, long-term, fixed-price contracts that could require us to provide integrated project management services outside our normal discrete business to act as project managers as well as service providers. Providing services on an integrated basis may require us to assume additional risks associated with cost over-runs, operating cost inflation, labor availability and productivity, supplier and contractor pricing and performance, and potential claims for liquidated damages. For example, we generally rely on third-party subcontractors and equipment providers to assist us with the completion of our contracts. To the extent that we cannot engage subcontractors or acquire equipment or materials, our ability to complete a project in a timely fashion or at a profit may be impaired. If the amount we are required to pay for these goods and services exceeds the amount we have estimated in bidding for fixed-price work, we could experience losses in the performance of these contracts. These delays and additional costs may be substantial, and we may be required to compensate the NOCs for these delays. This may reduce the profit to be realized or result in a loss on a project. Currently, long-term, fixed price contracts with NOCs do not comprise a significant portion of our business. However, in the future, based on the anticipated growth of NOCs, we expect our business with NOCs to grow relative to our other business, with these types of contracts likely comprising a more significant portion of our business.

Our acquisitions, dispositions, and investments may not result in the realization of savings, the creation of efficiencies, the generation of cash or income, or the reduction of risk, which may have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We continually seek opportunities to maximize efficiency and value through various transactions, including purchases or sales of assets, businesses, investments, or joint ventures. These transactions are intended to result in the realization of savings, the creation of efficiencies, the offering of new products or services, the generation of cash or income, or the reduction of risk. Acquisition transactions may be financed by additional borrowings or by the issuance of our common stock. These transactions may also affect our consolidated results of operations.

These transactions also involve risks, and we cannot ensure that:

- any acquisitions would result in an increase in income;
- any acquisitions would be successfully integrated into our operations and internal controls;
- the due diligence prior to an acquisition would uncover situations that could result in financial or legal exposure, including under the FCPA, or that we will appropriately quantify the exposure from known risks;
- any disposition would not result in decreased earnings, revenue, or cash flow;
- use of cash for acquisitions would not adversely affect our cash available for capital expenditures and other uses;
- any dispositions, investments, acquisitions, or integrations would not divert management resources; or
- any dispositions, investments, acquisitions, or integrations would not have a material adverse effect on our results of operations or financial condition.

Actions of and disputes with our joint venture partners could have a material adverse effect on the business and results of operations of our joint ventures and, in turn, our business and consolidated results of operations.
We conduct some operations through joint ventures, where control may be shared with unaffiliated third parties. As with any joint venture arrangement, differences in views among the joint venture participants may result in delayed decisions or in failures to agree on major issues. We also cannot control the actions of our joint venture partners, including any nonperformance, default, or bankruptcy of our joint venture partners. These factors could have a material adverse effect on the business and results of operations of our joint ventures and, in turn, our business and consolidated results of operations.

Failure on our part to comply with applicable environmental requirements could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.
Our businesses are subject to a variety of environmental laws, rules, and regulations in the United States and other countries, including those covering hazardous materials and requiring emission performance standards for facilities. For example, our well service operations routinely involve the handling of significant amounts of waste materials, some of which are classified as hazardous substances. We also store, transport, and use radioactive and explosive materials in certain of our operations. Environmental requirements include, for example, those concerning:

- the containment and disposal of hazardous substances, oilfield waste, and other waste materials;
- the importation and use of radioactive materials;
- the use of underground storage tanks; and
- the use of underground injection wells.

Environmental and other similar requirements generally are becoming increasingly strict. Sanctions for failure to comply with these requirements, many of which may be applied retroactively, may include:

- administrative, civil, and criminal penalties;
- revocation of permits to conduct business; and
- corrective action orders, including orders to investigate and/or clean up contamination.

Failure on our part to comply with applicable environmental requirements could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition. We are also exposed to costs arising from environmental compliance, including compliance with changes in or expansion of environmental requirements, which could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Liability for cleanup costs, natural resource damages, and other damages arising as a result of environmental laws could be substantial and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.
We are exposed to claims under environmental requirements and, from time to time, such claims have been made against us. In the United States, environmental requirements and regulations typically impose strict liability. Strict liability means that in some situations we could be exposed to liability for cleanup costs, natural resource damages, and other damages as a result of our conduct that was lawful at the time it occurred or the conduct of prior operators or other third parties. Liability for damages arising as a result of environmental laws could be substantial and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We are periodically notified of potential liabilities at federal and state superfund sites. These potential liabilities may arise from both historical Halliburton operations and the historical operations of companies that we have acquired. Our exposure at these sites may be materially impacted by unforeseen adverse developments both in the final remediation costs and with respect to the final allocation among the various parties involved at the sites. For any particular federal or state superfund site, since our estimated liability is typically within a range and our accrued liability may be the amount on the low end of that range, our actual liability could eventually be well in excess of the amount accrued. The relevant regulatory agency may bring suit against us for amounts in excess of what we have accrued and what we believe is our proportionate share of remediation costs at any superfund site. We also could be subject to third-party claims, including punitive damages, with respect to environmental matters for which we have been named as a potentially responsible party.

Existing or future laws, regulations, treaties or international agreements related to greenhouse gases and climate change could have a negative impact on our business and may result in additional compliance obligations with respect to the release, capture, and use of carbon dioxide that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.
Changes in environmental requirements may negatively impact demand for our services. For example, oil and natural gas exploration and production may decline as a result of environmental requirements (including land use policies responsive to environmental concerns). State, national, and international governments and agencies have been evaluating climate-related legislation and other regulatory initiatives that would restrict emissions of greenhouse gases in areas in which we conduct business. Because our business depends on the level of activity in the oil and natural gas industry, existing or future laws, regulations, treaties or international agreements related to greenhouse gases and climate change, including incentives to conserve energy or use alternative energy sources, could have a negative impact on our business if such laws, regulations, treaties, or international agreements reduce the worldwide demand for oil and natural gas. Likewise, such restrictions may result in additional compliance obligations with respect to the release, capture, and use of carbon dioxide that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete natural gas and oil wells and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.
We are a leading provider of hydraulic fracturing services, a process that creates fractures extending from the well bore through the rock formation to enable natural gas or oil to move more easily through the rock pores to a production well. Bills introduced in the last Congress asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would have required the reporting and public disclosure of chemicals used in the fracturing process. This legislation, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays and increased operating costs. During the first quarter of 2010, the United States Environmental Protection Agency (EPA) announced it will begin a detailed scientific study of hydraulic fracturing and the alleged effect on surface and ground water. We have submitted a variety of chemical information on our fracturing fluid products and related data to the Agency. These submissions have been made in accordance with a schedule we agreed to with EPA and are subject to protections for confidential business information. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete natural gas and oil wells and could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Changes in, compliance with, or our failure to comply with laws in the countries in which we conduct business may negatively impact our ability to provide services in, make sales of equipment to, and transfer personnel or equipment among, some of those countries and could have a material adverse affect on our consolidated results of operations.

In the countries in which we conduct business, we are subject to multiple and, at times, inconsistent regulatory regimes, including those that govern our use of radioactive materials, explosives, and chemicals in the course of our operations. Various national and international regulatory regimes govern the shipment of these items. Many countries, but not all, impose special controls upon the export and import of radioactive materials, explosives, and chemicals. Our ability to do business is subject to maintaining required licenses and complying with these multiple regulatory requirements applicable to these special products. In addition, the various laws governing import and export of both products and technology apply to a wide range of services and products we offer. In turn, this can affect our employment practices of hiring people of different nationalities because these laws may prohibit or limit access to some products or technology by employees of various nationalities. Changes in, compliance with, or our failure to comply with these laws may negatively impact our ability to provide services in, make sales of equipment to, and transfer personnel or equipment among some of the countries in which we operate and could have a material adverse effect on our business and consolidated results of operations.

Constraints in the supply of raw materials can have a material adverse effect on our consolidated results of operations.
Raw materials essential to our business are normally readily available. Market conditions can trigger constraints in the supply chain of certain raw materials, such as sand, cement, and specialty metals, which can have a material adverse effect on our business and consolidated results of operations. The majority of our risk associated with supply chain constraints occurs in those situations where we have a relationship with a single supplier for a particular resource.

Our failure to protect our proprietary information and any successful intellectual property challenges or infringement proceedings against us could materially and adversely affect our competitive position.
We rely on a variety of intellectual property rights that we use in our services and products. We may not be able to successfully preserve these intellectual property rights in the future, and these rights could be invalidated, circumvented, or challenged. In addition, the laws of some foreign countries in which our services and products may be sold do not protect intellectual property rights to the same extent as the laws of the United States. Our failure to protect our proprietary information and any successful intellectual property challenges or infringement proceedings against us could materially and adversely affect our competitive position.

If we are not able to design, develop, and produce commercially competitive products and to implement commercially competitive services in a timely manner in response to changes in technology, our business and consolidated results of operations could be materially and adversely affected, and the value of our intellectual property may be reduced.
The market for our services and products is characterized by continual technological developments to provide better and more reliable performance and services. If we are not able to design, develop, and produce commercially competitive products and to implement commercially competitive services in a timely manner in response to changes in technology, our business and revenue could be materially and adversely affected, and the value of our intellectual property may be reduced. Likewise, if our proprietary technologies, equipment and facilities, or work processes become obsolete, we may no longer be competitive, and our business and consolidated results of operations could be materially and adversely affected.

The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.
We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

Our ability to operate and our growth potential could be materially and adversely affected if we cannot employ and retain technical personnel at a competitive cost.
Many of the services that we provide and the products that we sell are complex and highly engineered and often must perform or be performed in harsh conditions. We believe that our success depends upon our ability to employ and retain technical personnel with the ability to design, utilize, and enhance these services and products. In addition, our ability to expand our operations depends in part on our ability to increase our skilled labor force. A significant increase in the wages paid by competing employers could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. If either of these events were to occur, our cost structure could increase, our margins could decrease, and any growth potential could be impaired.

Our business could be materially and adversely affected by severe or unseasonable weather, particularly in the Gulf of Mexico where we have operations.
Our business could be materially and adversely affected by severe weather, particularly in the Gulf of Mexico where we have operations. Repercussions of severe weather conditions may include:

- evacuation of personnel and curtailment of services;
- weather-related damage to offshore drilling rigs resulting in suspension of operations;
- weather-related damage to our facilities and project work sites;
- inability to deliver materials to jobsites in accordance with contract schedules; and
- loss of productivity.

Because demand for natural gas in the United States drives a significant amount of our business, warmer than normal winters in the United States are detrimental to the demand for our services to natural gas producers.

Item 1(b). Unresolved Staff Comments.
None.

Item 2. Properties.

We own or lease numerous properties in domestic and foreign locations. The following locations represent our major facilities and corporate offices.

Location	Owned/Leased	Description
Completion and Production segment:		
Arbroath, United Kingdom	Owned	Manufacturing facility
Johor, Malaysia	Leased	Manufacturing facility
Monterrey, Mexico	Leased	Manufacturing facility
Sao Jose dos Campos, Brazil	Leased	Manufacturing facility
Stavanger, Norway	Leased	Research and development laboratory
Drilling and Evaluation segment:		
Alvarado, Texas	Owned/Leased	Manufacturing facility
Nisku, Canada	Owned	Manufacturing facility
Singapore	Leased	Manufacturing and technology facility
The Woodlands, Texas	Leased	Manufacturing facility
Shared/corporate facilities:		
Carrollton, Texas	Owned	Manufacturing facility
Dubai, United Arab Emirates	Leased	Corporate executive offices
Duncan, Oklahoma	Owned	Manufacturing, technology, and campus facilities
Houston, Texas	Owned	Corporate executive offices, manufacturing, technology, and campus facilities
Houston, Texas	Owned	Campus facility
Houston, Texas	Leased	Campus facility
Port Harcourt, Nigeria	Owned	Campus facility
Pune, India	Leased	Technology facility
Villahermosa, Mexico	Owned	Campus facility

All of our owned properties are unencumbered.

In addition, we have 170 international and 109 United States field camps from which we deliver our services and products. We also have numerous small facilities that include sales offices, project offices, and bulk storage facilities throughout the world.

We believe all properties that we currently occupy are suitable for their intended use.

Item 3. Legal Proceedings.

The Gulf of Mexico/Macondo well incident

Overview. The semisubmersible drilling rig, Deepwater Horizon, sank on April 22, 2010 after an explosion and fire onboard the rig that began on April 20, 2010. The Deepwater Horizon was owned by Transocean Ltd. and had been drilling the Macondo exploration well in Mississippi Canyon Block 252 in the Gulf of Mexico for the lease operator, BP Exploration, an indirect wholly owned subsidiary of BP p.l.c. We performed a variety of services for BP Exploration, including cementing, mud logging, directional drilling, measurement-while-drilling, and rig data acquisition services. Crude oil flowing from the well site spread across thousands of square miles of the Gulf of Mexico and reached the United States Gulf Coast. Numerous attempts at estimating the volume of oil spilled have been made by various groups, and on August 2, 2010 the federal government published an estimate that approximately 4.9 million barrels of oil were discharged from the well. Efforts to contain the flow of hydrocarbons from the well were led by the United States government and by BP. The flow of hydrocarbons from the well ceased on July 15, 2010, and the well was permanently capped on September 19, 2010. There were eleven fatalities and a number of injuries as a result of the Macondo well incident.

As of December 31, 2010, we had not accrued any amounts related to this matter because we do not believe that a loss is probable. We are currently unable to estimate the full impact the Macondo well incident will have on us. Further, an estimate of possible loss or range of loss related to this matter cannot be made. Considering the complexity of the Macondo well, however, and the number of investigations being conducted and lawsuits pending, as discussed below, new information or future developments may require us to adjust our liability assessment, and liabilities arising out of this matter could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Investigations and Regulatory Action. The United States Department of Homeland Security and Department of the Interior are jointly investigating the cause of the Macondo well incident. The United States Coast Guard, a component of the United States Department of Homeland Security, and the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly known as the Minerals Management Service), a bureau of the United States Department of the Interior, share jurisdiction over the investigation into the Macondo well incident and have formed a joint investigation team that continues to review information and hold hearings regarding the incident (Marine Board Investigation). We are named as one of the 16 parties-in-interest in the Marine Board Investigation. In addition, other investigations are underway by the Chemical Safety Board, the National Academy of Sciences, and the National Commission that the President of the United States has established to, among other things, examine the relevant facts and circumstances concerning the causes of the Macondo well incident and develop options for guarding against future oil spills associated with offshore drilling. We are assisting in efforts to identify the factors that led to the Macondo well incident and have participated and intend to continue participating in various hearings relating to the incident that are held by, among others, certain of the agencies referred to above and various committees and subcommittees of the House of Representatives and the Senate of the United States.

In May 2010, the United States Department of the Interior effectively suspended all offshore deepwater drilling projects in the United States Gulf of Mexico. The suspension was lifted in October 2010. Since that time, the Department of the Interior has issued guidance for drillers that intend to resume deepwater drilling activity. There has been no material increase, however, in the level of drilling activity in the Gulf of Mexico since the suspension was lifted, and we believe that the prospects for any significant increase will remain uncertain through the first half, and perhaps the full year, of 2011. For additional information, see Item 1(a), “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Business Environment and Results of Operations.”

DOJ Investigations and Actions. On June 1, 2010, the United States Attorney General announced that the Department of Justice (DOJ) was launching civil and criminal investigations into the Macondo well incident to closely examine the actions of those involved, and that the DOJ was working with attorneys general of states affected by the Macondo well incident. The DOJ announced that it was reviewing, among other traditional criminal statutes, possible violations of and liabilities under The Clean Water Act (CWA), The Oil Pollution Act of 1990 (OPA), The Migratory Bird Treaty Act of 1918 (MBTA), and the Endangered Species Act of 1973 (ESA).

The CWA provides authority for civil and criminal penalties for discharges of oil into or upon navigable waters of the United States, adjoining shorelines, or in connection with the Outer Continental Shelf Lands Act in quantities that are deemed harmful. Criminal sanctions under the CWA can be assessed for negligent discharges (up to $50,000 per day of violation), for knowing discharges (up to $100,000 per day of violation), and for knowing endangerment (up to $2 million per violation), and federal agencies could be precluded from contracting with a company that is criminally sanctioned under the CWA. Civil proceedings under the CWA can be commenced against an “owner, operator or person in charge of any vessel or offshore facility that discharged oil or a hazardous substance.” The civil penalties that can be imposed against responsible parties range from up to $1,100 per barrel of oil discharged in the case of those found strictly liable to $4,300 per barrel of oil discharged in the case of those found to have been grossly negligent.

The OPA establishes liability for discharges of oil from vessels, onshore facilities, and offshore facilities into or upon the navigable waters of the United States. Under the OPA, the “responsible party” for the discharging vessel or facility is liable for removal and response costs as well as for damages, including recovery costs to contain and remove discharged oil and compensation for injury to natural resources. The cap on liability under the OPA is the full cost of removal of the discharged oil plus up to $75 million for natural resources damages, except that the cap on natural resources damages does not apply in the event the damage was proximately caused by gross negligence or the violation of certain federal standards. The OPA defines the set of responsible parties differently depending on whether the source of the discharge is a vessel or an offshore facility. Liability for vessels is imposed on owners and operators; liability for offshore facilities is imposed on the holder of the permit or lessee of the area in which the facility is located.

The MBTA and the ESA provide penalties for injury and death to wildlife and bird species. The MBTA provides that violators are strictly liable and provides for fines of up to $15,000 per bird killed and imprisonment of up to six months. The ESA provides for civil penalties for knowing violations that can range up to $25,000 per violation and, in the case of criminal penalties, up to $50,000 per violation.

In addition, the Alternative Fines Act may be applied in lieu of the express amount of the criminal fines that may be imposed under the statutes described above in the amount of twice the gross economic loss suffered by third parties (or twice the gross economic gain realized by the defendant, if greater).

On December 15, 2010, the DOJ filed a civil action seeking damages and injunctive relief against BP, Anadarko, Transocean and others for violations of the CWA and the OPA. The DOJ’s complaint seeks an action declaring that the defendants are strictly liable under the CWA as a result of harmful discharges of oil into the Gulf of Mexico and upon U.S. shorelines as a result of the Macondo well incident. The complaint also seeks an action declaring that the defendants are strictly liable under the OPA for the discharge of oil that has resulted in, among other things, injury to, loss of, loss of use of or destruction of natural resources and resource services in and around the Gulf of Mexico and the adjoining U.S. shorelines and resulting in removal costs and damages to the United States far exceeding $75 million. BP has been designated, and has accepted the designation, as a responsible party for the pollution under the CWA and the OPA. Others have also been named as responsible parties, and all responsible parties may be held jointly and severally liable for any damages under the OPA, although a responsible party may make a claim for contribution against any other “responsible party” it alleges contributed to the oil spill or any other person it alleges was the sole cause of the oil spill.

We were not named as a responsible party under the CWA or the OPA in the DOJ civil action, and we do not believe we are a "responsible party" under the CWA or the OPA. While we were not included in the DOJ's complaint, there can be no assurance that we will not be joined in the action or that the DOJ or other federal or state governmental authorities will not bring an action, whether civil or criminal, against us under other statutes or regulations. In connection with the DOJ's filing of the action, it announced that its criminal and civil investigations are continuing and that it will employ efforts to hold accountable those who are responsible for the incident. As of February 17, 2011, no criminal proceedings have been commenced against us.

In June 2010, we received a letter from the DOJ requesting thirty days advance notice of any event that may involve substantial transfers of cash or other corporate assets outside of the ordinary course of business. In our reply to the June 2010 DOJ letter, we conveyed our interest in briefing the DOJ on the services we provided on the Deepwater Horizon but indicated that we would not bind ourselves to the DOJ request. Subsequently, we have had and expect to continue to have discussions with the DOJ regarding the Macondo well incident and the request contained in the June 2010 DOJ letter.

Investigative Reports. On September 8, 2010, an incident investigation team assembled by BP issued the Deepwater Horizon Accident Investigation Report (BP Report). The BP Report outlines eight key findings of BP related to the possible causes of the Macondo well incident, including failures of cement barriers, failures of equipment provided by other service companies and the drilling contractor, and failures of judgment by BP and the drilling contractor. With respect to the BP Report's assessment that the cement barrier did not prevent hydrocarbons from entering the wellbore after cement placement, the BP Report concluded that, among other things, there were "weaknesses in cement design and testing." According to the BP Report, the BP incident investigation team did not review its analyses or conclusions with us or any other entity or governmental agency conducting a separate or independent investigation of the incident. In addition, the BP incident investigation team did not conduct any testing using our cementing products.

On January 11, 2011, the National Commission released its Investigation Report to the President of the United States regarding, among other things, the National Commission's conclusions of the causes of the Macondo well incident. According to the Investigation Report, the "immediate causes" of the incident were the result of a series of missteps, oversights, miscommunications and failures to appreciate risk by BP, Transocean, and us, although the National Commission acknowledged that there were still many things it did not know about the incident, such as the role of the blowout preventer. The National Commission also acknowledged that it may never know the extent to which each mistake or oversight caused the Macondo well incident, but concluded that the immediate cause was "a failure to contain hydrocarbon pressures in the well," and pointed to three things that could have contained those pressures: "the cement at the bottom of the well, the mud in the well and in the riser, and the blowout preventer." In addition, the Investigation Report stated that "primary cement failure was a direct cause of the blowout" and that cement testing performed by an independent laboratory "strongly suggests" that the foam cement slurry used on the Macondo well was unstable. The Investigation Report, however, acknowledges a fact widely accepted by the industry that cementing wells is a complex endeavor utilizing an inherently uncertain process in which failures are not uncommon and that, as a result, the industry utilizes the negative pressure test and cement bond log test, among others, to identify cementing failures that require remediation before further work on a well is performed.

The Investigation Report also sets forth the National Commission's findings on certain missteps, oversights and other factors that may have caused, or contributed to the cause of, the incident, including BP's decision to use a long string casing instead of a liner casing, BP's decision to use only six centralizers, BP's failure to run a cement bond log, BP's reliance on the primary cement job as a barrier to a possible blowout, BP's and Transocean's failure to properly conduct and interpret a negative-pressure test, BP's temporary abandonment procedures, and the failure of the drilling crew and our surface data logging specialist to recognize that an unplanned influx of oil, gas or fluid into the well (known as a "kick") was occurring. With respect to the National Commission's finding that our surface data logging specialist failed to recognize a kick, the Investigation Report acknowledged that there were simultaneous activities and other monitoring responsibilities that may have prevented the surface data logging specialist from recognizing a kick.

The Investigation Report also identified two general root causes of the Macondo well incident: systemic failures by industry management, which the National Commission labeled "the most significant failure at Macondo," and failures in governmental and regulatory oversight. The National Commission cited examples of failures by industry management such as BP's lack of controls to adequately identify or address risks arising from changes to well design and procedures, the failure of BP's and our processes for cement testing, communication failures among BP, Transocean, and us, including with respect to the difficulty of our cement job, Transocean's failure to adequately communicate lessons from a recent near-blowout, and the lack of processes to adequately assess the risk of decisions in relation to the time and cost those decisions would save. With respect to failures of governmental and regulatory oversight, the National Commission concluded that applicable drilling regulations were inadequate, in part because of a lack of resources and political support of the Minerals Management Service (MMS), and a lack of expertise and training of MMS personnel to enforce regulations that were in effect.

We expect National Commission staff to issue a separate, more detailed report regarding the causes of the Macondo well incident sometime in the first quarter 2011.

The Cementing Job and Reaction to Reports. We disagree with the BP Report and the National Commission regarding many of their findings and characterizations with respect to the cementing and surface data logging services on the Deepwater Horizon. We have provided information to the National Commission and its staff that we believe has been overlooked or selectively omitted from the Investigation Report. We intend to continue to vigorously defend ourselves in any investigation relating to our involvement with the Macondo well that we believe inaccurately evaluates or depicts our services on the Deepwater Horizon.

The cement slurry on the Deepwater Horizon was designed and prepared pursuant to well condition data provided by BP. Regardless of whether alleged weaknesses in cement design and testing are or are not ultimately established, and regardless of whether the cement slurry was utilized in similar applications or was prepared consistent with industry standards, we believe that had BP and others properly interpreted a negative-pressure test, this test would have revealed any problems with the cement. In addition, had BP designed the Macondo well to allow a full cement bond log test or if BP had conducted even a partial cement bond log test, the test likely would have revealed any problems with the cement. BP, however, elected not to conduct any cement bond log test, and with others misinterpreted the negative-pressure test, both of which could have resulted in remedial action, if appropriate, with respect to the cementing services.

At this time we cannot predict the impact of the Investigation Report or the conclusions of future reports of the National Commission, the Marine Board Investigation, the Chemical Safety Board, the National Academy of Sciences, Congressional committees, or any other governmental or private entity. In addition, although we have not been served by the DOJ or any state agency, we cannot predict whether their investigations or any other report or investigation will have an influence on or result in our being named as a party in any action alleging violation of a statute or regulation, whether federal or state and whether criminal or civil.

We intend to continue to cooperate fully with all governmental hearings, investigations, and requests for information relating to the Macondo well incident. We cannot predict the outcome of, or the costs to be incurred in connection with, any of these hearings or investigations, and therefore we cannot predict the potential impact they may have on us.

Litigation. Beginning on April 21, 2010, plaintiffs started filing lawsuits relating to the Macondo well incident. Generally, those lawsuits allege either (1) damages arising from the oil spill pollution and contamination (e.g., diminution of property value, lost tax revenue, lost business revenue, lost tourist dollars, inability to engage in recreational or commercial activities) or (2) wrongful death or personal injuries. To date, we have been named along with other unaffiliated defendants in more than 330 complaints, most of which are alleged class actions, involving pollution damage claims and at least 28 personal injury lawsuits involving six decedents and 54 allegedly injured persons who were on the drilling rig at the time of the incident. Another six lawsuits naming us and others relate to alleged personal injuries sustained by those responding to the explosion and oil spill. Plaintiffs originally filed the lawsuits described above in federal and state courts throughout the United States, including Alabama, Delaware, Florida, Georgia, Kentucky, Louisiana, Mississippi, South Carolina, Tennessee, Texas, and Virginia. Except for approximately 25 lawsuits not yet consolidated, one lawsuit that is proceeding in Louisiana state court, and one lawsuit that is proceeding in Texas state court, the Judicial Panel on Multi-District Litigation ordered all of the lawsuits consolidated in a multi-district litigation (MDL) proceeding before Judge Carl Barbier in the U.S. Eastern District of Louisiana. The pollution complaints generally allege, among other things, negligence and gross negligence, property damages, taking of protected species, and potential economic losses as a result of environmental pollution and generally seek awards of unspecified economic, compensatory, and punitive damages, as well as injunctive relief. Plaintiffs in these pollution cases have brought suit under various legal provisions, including the OPA, the CWA, the MBTA, the ESA, the Outer Continental Shelf Lands Act, the Longshoremen and Harbor Workers Compensation Act, general maritime law, STATE COMMON LAW, and various state environmental and products liability statutes. Furthermore, the pollution complaints include suits brought by governmental entities, including the State of Alabama, Plaquemines Parish, and three Mexican states. The wrongful death and other personal injury complaints generally allege negligence and gross negligence and seek awards of compensatory damages, including unspecified economic damages and punitive damages. We have retained counsel and are investigating and evaluating the claims, the theories of recovery, damages asserted, and our respective defenses to all of these claims.

According to case management and pre-trial orders, with respect to the MDL, the court may try one or more OPA “test cases” as early as third quarter 2011. These test cases, the number and specificity of which have not been determined, will consist of claims brought against BP as a responsible party under the OPA. The same judge is also presiding over a separate proceeding filed by Transocean under the Limitation of Liability Act (Limitation Action). In the Limitation Action, Transocean seeks to limit its liability for claims arising out of the Macondo well incident to the value of the rig and its freight. Although the Limitation Action is not consolidated in the MDL, to this point the judge is effectively treating the two proceedings as associated cases. Although we are not yet formally a party to the Limitation Action, we expect that Transocean will tender all defendants into the Limitation Action in February 2011. As a result of that anticipated tender, all defendants will be treated as direct defendants to the plaintiffs’ claims as if the plaintiffs had sued each defendant directly.

In the Limitation Action, the judge intends to determine the allocation of liability among all defendants in the hundreds of lawsuits associated with the Macondo well incident that are pending in his court. More specifically, the court intends to try one or more “personal injury/wrongful death test cases” and one or more economic damage claim “test cases” in the first quarter 2012 in an attempt to determine liability, limitation, exoneration and fault allocation with regard to all of the defendants. We do not believe, however, that a single apportionment of liability in the Limitation Action is properly applied to the hundreds of lawsuits pending in the MDL Proceeding. Damages for the personal injury/wrongful death and economic damage claim "test cases" tried in the first quarter 2012, including punitive damages, are expected to be tried in a second phase of the Limitation Action. Under ordinary MDL procedures, such trials would, unless waived by the respective parties, be tried in the courts from which they were transferred into the MDL. It remains unclear, however, what impact the overlay of the Limitation Action will have on where these matters are tried.

Additional civil lawsuits may be filed against us. Document discovery and depositions among the parties to the MDL have begun. The deadline for defendants to file cross claims and third-party claims arising out of the Macondo well incident against other defendants is March 18, 2011.

We intend to vigorously defend any litigation, fines, and/or penalties relating to the Macondo well incident.

Shareholder derivative case. In February 2011, a shareholder derivative lawsuit was filed in Harris County, Texas naming us as a nominal defendant and certain of our directors and officers as defendants. This case alleges that these defendants, among other things, breached fiduciary duties of good faith and loyalty by failing to properly exercise oversight responsibilities and establish adequate internal controls, including controls and procedures related to cement testing and the communication of test results, as they relate to the Deepwater Horizon incident. Due to the preliminary status of the lawsuit and uncertainties related to litigation, we are unable to evaluate the likelihood of either a favorable or unfavorable outcome.

Indemnification and Insurance. Our contract with BP Exploration relating to the Macondo well provides for our indemnification for potential claims and expenses relating to the Macondo well incident, including those resulting from pollution or contamination (other than claims by our employees, loss or damage to our property, and any pollution emanating directly from our equipment). Also, under our contract with BP Exploration, we have, among other things, generally agreed to indemnify BP Exploration and other contractors performing work on the well for claims for personal injury of our employees and subcontractors, as well as for damage to our property. In turn, we believe that BP Exploration is obligated to obtain agreement by other contractors performing work on the well to indemnify us for claims for personal injury of their employees or subcontractors as well as for damages to their property.

In addition to the contractual indemnity, we have a general liability insurance program of $600 million. Our insurance is designed to cover claims by businesses and individuals made against us in the event of property damage, injury or death and, among other things, claims relating to environmental damage. To the extent we incur any losses beyond those covered by indemnification, there can be no assurance that our insurance policies will cover all potential claims and expenses relating to the Macondo well incident. Insurance coverage can be the subject of uncertainties and, particularly in the event of large claims, potential disputes with insurance carriers, as well as other potential parties claiming insured status under our insurance policies.

Given the potential amounts involved, BP Exploration and other indemnifying parties may seek to avoid their indemnification obligations. In particular, while we do not believe there is any justification to do so, BP Exploration, in response to our request for indemnification, on June 25, 2010 generally reserved all of its rights and stated that it is premature to conclude that it is obligated to indemnify us. In doing so, BP Exploration has asserted that the facts were not sufficiently developed to determine who is responsible, and cited a variety of possible legal theories based upon the contract and facts still to be developed. As indicated above, all cross claims among defendants must be filed by March 18, 2011. We expect that all defendants will make claims against each other and deny that they owe any indemnification or other obligations to any other defendant.

Indemnification for criminal fines or penalties, if any, may not be available if a court were to find such indemnification unenforceable as against public policy. We do not expect, however, public policy to limit substantially the enforceability of our contractual right to indemnification with respect to liabilities other than criminal fines and penalties, if any. We may not be insured with respect to civil or criminal fines or penalties, if any, pursuant to the terms of our insurance policies.

We believe the law likely to be held applicable to matters relating to the Macondo well incident does not allow for enforcement of indemnification of persons who are found to be grossly negligent, although we do not believe the performance of our services on the Deepwater Horizon constituted gross negligence. In addition, certain state laws, if deemed to apply, may not allow for enforcement of indemnification of persons who are found to be negligent with respect to personal injury claims. In addition, financial analysts and the press have speculated about the financial capacity of BP, and whether it might seek to avoid indemnification obligations in bankruptcy proceedings. We consider the likelihood of a BP bankruptcy to be remote.

TSKJ matters

Background. As a result of an ongoing FCPA investigation at the time of the KBR separation, we provided indemnification in favor of KBR under the master separation agreement for certain contingent liabilities, including our indemnification of KBR and any of its greater than 50%-owned subsidiaries as of November 20, 2006, the date of the master separation agreement, for fines or other monetary penalties or direct monetary damages, including disgorgement, as a result of a claim made or assessed by a governmental authority in the United States, the United Kingdom, France, Nigeria, Switzerland, and/or Algeria, or a settlement thereof, related to alleged or actual violations occurring prior to November 20, 2006 of the FCPA or particular, analogous applicable foreign statutes, laws, rules, and regulations in connection with investigations pending as of that date, including with respect to the construction and subsequent expansion by TSKJ of a multibillion dollar natural gas liquefaction complex and related facilities at Bonny Island in Rivers State, Nigeria. As a condition of our indemnity, we have control over the investigation, defense, and/or settlement of these matters. We have the right to terminate the indemnity in the event KBR elects to take control over the investigation, defense, and/or settlement or refuses to agree to a settlement negotiated and presented by us.

TSKJ is a private limited liability company registered in Madeira, Portugal whose members are Technip SA of France, Snamprogetti Netherlands B.V. (a subsidiary of Saipem SpA of Italy), JGC Corporation of Japan, and Kellogg Brown & Root LLC (a subsidiary of KBR), each of which had an approximate 25% beneficial interest in the venture. Part of KBR’s ownership in TSKJ was held through M.W. Kellogg Limited (MWKL), a United Kingdom joint venture and subcontractor on the Bonny Island project, in which KBR beneficially owned a 55% interest at the time of the execution of the master separation agreement. TSKJ and other similarly owned entities entered into various contracts to build and expand the liquefied natural gas project for Nigeria LNG Limited, which is owned by the Nigerian National Petroleum Corporation, Shell Gas B.V., Cleag Limited (an affiliate of Total), and Agip International B.V. (an affiliate of ENI SpA of Italy).

DOJ, SEC, United Kingdom, and Nigerian Government investigations resolved. In 2009, the FCPA investigations by the DOJ and the SEC were resolved with respect to KBR and us. The DOJ and SEC investigations resulted from allegations of improper payments to government officials in Nigeria in connection with the construction and subsequent expansion by TSKJ of the Bonny Island project.

The DOJ investigation was resolved with respect to us with a non-prosecution agreement in which the DOJ agreed not to bring FCPA or bid coordination-related charges against us with respect to the matters under investigation, and in which we agreed to continue to cooperate with the DOJ's ongoing investigation and to refrain from and self-report certain FCPA violations. The DOJ agreement did not provide a monitor for us.

KBR has agreed that our indemnification obligations with respect to the DOJ and SEC FCPA investigations have been fully satisfied.

As part of the resolution of the SEC investigation, we retained an independent consultant to conduct a 60-day review and evaluation of our internal controls and record-keeping policies as they relate to the FCPA. The review and evaluation were completed during the second quarter of 2009, and we have implemented the consultant's recommendations. As a result of the substantial enhancement of our anti-bribery and foreign agent internal controls and record-keeping procedures prior to the review of the independent consultant, we do not expect the implementation of the consultant's recommendations to materially impact our long-term strategy to grow our international operations. In 2010, the independent consultant performed a 30-day, follow-up review, confirming that we have implemented the recommendations and continued the application of our current policies and procedures and to recommend any additional improvements.

In December 2010, we reached a settlement agreement to resolve charges filed by the Federal Government of Nigeria (FGN) in late 2010. Pursuant to the agreement, all lawsuits and charges against KBR and our corporate entities and associated persons have been withdrawn, and the FGN agreed not to bring any further criminal charges or civil claims against those entities or persons, and we agreed to pay $33 million to the FGN and to pay an additional $2 million for FGN's attorneys' fees and other expenses. Among other provisions, we agreed to provide reasonable assistance in the FGN's effort to recover amounts frozen in a Swiss bank account of a former TSKJ agent and affirmed a continuing commitment with regard to corporate governance.

In February 2011, an investigation in the United Kingdom by the Serious Fraud Office (SFO) focused on the actions of MWKL was resolved between the SFO and MWKL in full and final settlement of the case. The agreement was in the form of a civil settlement in which the SFO recognized that MWKL took no part in the criminal activity which generated the funds. Our indemnity for penalties under the master separation agreement with respect to MWKL was limited to 55% of such penalties, which was KBR's beneficial ownership interest in MWKL at the time of the execution of the master separation agreement.

The DOJ, SEC, United Kingdom, and FGN settlements and other future investigations and settlements, if any, could result in third-party claims against us, which may include claims for special, indirect, derivative or consequential damages, damage to our business or reputation, loss of, or adverse effect on, cash flow, assets, goodwill, results of operations, business prospects, profits or business value or claims by directors, officers, employees, affiliates, advisors, attorneys, agents, debt holders, or other interest holders or constituents of us or our current or former subsidiaries.

Our indemnity of KBR and its majority-owned subsidiaries continues with respect to other investigations within the scope of our indemnity. Our indemnification obligation to KBR does not include losses resulting from third-party claims against KBR, including claims for special, indirect, derivative or consequential damages, nor does our indemnification apply to damage to KBR's business or reputation, loss of, or adverse effect on, cash flow, assets, goodwill, results of operations, business prospects, profits or business value or claims by directors, officers, employees, affiliates, advisors, attorneys, agents, debt holders, or other interest holders or constituents of KBR or KBR's current or former subsidiaries.

At this time, no other claims by governmental authorities in foreign jurisdictions have been asserted against the indemnified parties.

Barracuda-Caratinga arbitration

We also provided indemnification in favor of KBR under the master separation agreement for all out-of-pocket cash costs and expenses (except for legal fees and other expenses of the arbitration so long as KBR controls and directs it), or cash settlements or cash arbitration awards, KBR may incur after November 20, 2006 as a result of the replacement of certain subsea flowline bolts installed in connection with the Barracuda-Caratinga project. Under the master separation agreement, KBR currently controls the defense, counterclaim, and settlement of the subsea flowline bolts matter. As a condition of our indemnity, for any settlement to be binding upon us, KBR must secure our prior written consent to such settlement's terms. We have the right to terminate the indemnity in the event KBR enters into any settlement without our prior written consent.

At Petrobras' direction, KBR replaced certain bolts located on the subsea flowlines that failed through mid-November 2005, and KBR has informed us that additional bolts have failed thereafter, which were replaced by Petrobras. These failed bolts were identified by Petrobras when it conducted inspections of the bolts. We understand KBR believes several possible solutions may exist, including replacement of the bolts. Initial estimates by KBR indicated that costs of these various solutions ranged up to $148 million. In March 2006, Petrobras commenced arbitration against KBR claiming $220 million plus interest for the cost of monitoring and replacing the defective bolts and all related costs and expenses of the arbitration, including the cost of attorneys' fees. The arbitration panel held an evidentiary hearing in March 2008 to determine which party is responsible for the designation of the material used for the bolts. On May 13, 2009, the arbitration panel held that KBR and not Petrobras selected the material to be used for the bolts. Accordingly, the arbitration panel held that there is no implied warranty by Petrobras to KBR as to the suitability of the bolt material and that the parties' rights are to be governed by the express terms of their contract. The parties presented evidence and witnesses to the panel in May 2010, and final arguments were presented in August 2010. We are awaiting a final decision from the arbitration panel.

Securities and related litigation

In June 2002, a class action lawsuit was filed against us in federal court alleging violations of the federal securities laws after the SEC initiated an investigation in connection with our change in accounting for revenue on long-term construction projects and related disclosures. In the weeks that followed, approximately twenty similar class actions were filed against us. Several of those lawsuits also named as defendants several of our present or former officers and directors. The class action cases were later consolidated, and the amended consolidated class action complaint, styled Richard Moore, et al. v. Halliburton Company, et al., was filed and served upon us in April 2003. As a result of a substitution of lead plaintiffs, the case is now styled Archdiocese of Milwaukee Supporting Fund (AMSF) v. Halliburton Company, et al. We settled with the SEC in the second quarter of 2004.

In June 2003, the lead plaintiffs filed a motion for leave to file a second amended consolidated complaint, which was granted by the court. In addition to restating the original accounting and disclosure claims, the second amended consolidated complaint included claims arising out of the 1998 acquisition of Dresser Industries, Inc. by Halliburton, including that we failed to timely disclose the resulting asbestos liability exposure.

In April 2005, the court appointed new co-lead counsel and named AMSF the new lead plaintiff, directing that it file a third consolidated amended complaint and that we file our motion to dismiss. The court held oral arguments on that motion in August 2005, at which time the court took the motion under advisement. In March 2006, the court entered an order in which it granted the motion to dismiss with respect to claims arising prior to June 1999 and granted the motion with respect to certain other claims while permitting AMSF to re-plead some of those claims to correct deficiencies in its earlier complaint. In April 2006, AMSF filed its fourth amended consolidated complaint. We filed a motion to dismiss those portions of the complaint that had been re-pled. A hearing was held on that motion in July 2006, and in March 2007 the court ordered dismissal of the claims against all individual defendants other than our Chief Executive Officer (CEO). The court ordered that the case proceed against our CEO and Halliburton.

In September 2007, AMSF filed a motion for class certification, and our response was filed in November 2007. The court held a hearing in March 2008, and issued an order November 3, 2008 denying AMSF's motion for class certification. AMSF then filed a motion with the Fifth Circuit Court of Appeals requesting permission to appeal the district court's order denying class certification. The Fifth Circuit granted AMSF's motion. Both parties filed briefs, and the Fifth Circuit heard oral argument in December of 2009. The Fifth Circuit affirmed the district court's order denying class certification. On May 13, 2010, AMSF filed a writ of certiorari in the United States Supreme Court. In early January 2011, the Supreme Court granted AMSF's writ of certiorari and accepted the appeal. The parties will now submit legal briefs to the Court and the Court will hear oral arguments in April 2011. The appeal is limited to review of the legal ruling of the Fifth Circuit affirming the lower court's order denying class certification and will not include review of the facts of the underlying lawsuit.

Shareholder derivative cases

In May 2009, two shareholder derivative lawsuits involving us and KBR were filed in Harris County, Texas naming as defendants various current and retired Halliburton directors and officers and current KBR directors. These cases allege that the individual Halliburton defendants violated their fiduciary duties of good faith and loyalty to the detriment of Halliburton and its shareholders by failing to properly exercise oversight responsibilities and establish adequate internal controls. The District Court consolidated the two cases and the plaintiffs filed a consolidated petition against current and former Halliburton directors and officers only containing various allegations of wrongdoing including violations of the FCPA, claimed KBR offenses while acting as a government contractor in Iraq, claimed KBR offenses and fraud under United States government contracts, Halliburton activity in Iran, and illegal kickbacks. Our Board of Directors has designated a special committee of independent directors to oversee the investigation of the allegations made in the lawsuits and make recommendations to the Board on actions that should be taken.

Environmental

We are subject to numerous environmental, legal, and regulatory requirements related to our operations worldwide. In the United States, these laws and regulations include, among others:

- the Comprehensive Environmental Response, Compensation, and Liability Act;
- the Resource Conservation and Recovery Act;
- the Clean Air Act;
- the Federal Water Pollution Control Act; and
- the Toxic Substances Control Act.

In addition to the federal laws and regulations, states and other countries where we do business often have numerous environmental, legal, and regulatory requirements by which we must abide. We evaluate and address the environmental impact of our operations by assessing and remediating contaminated properties in order to avoid future liabilities and comply with environmental, legal, and regulatory requirements. On occasion, we are involved in specific environmental litigation and claims, including the remediation of properties we own or have operated, as well as efforts to meet or correct compliance-related matters. Our Health, Safety and Environment group has several programs in place to maintain environmental leadership and to prevent the occurrence of environmental contamination.

We do not expect costs related to these remediation requirements to have a material adverse effect on our consolidated financial position or our results of operations.

We have subsidiaries that have been named as potentially responsible parties along with other third parties for 12 federal and state superfund sites for which we have established reserves. As of December 31, 2010, those 12 sites accounted for approximately $10 million of our total $47 million reserve. For any particular federal or state superfund site, since our estimated liability is typically within a range and our accrued liability may be the amount on the low end of that range, our actual liability could eventually be well in excess of the amount accrued. Despite attempts to resolve these superfund matters, the relevant regulatory agency may at any time bring suit against us for amounts in excess of the amount accrued. With respect to some superfund sites, we have been named a potentially responsible party by a regulatory agency; however, in each of those cases, we do not believe we have any material liability. We also could be subject to third-party claims with respect to environmental matters for which we have been named as a potentially responsible party.

Item 4. Specialized Disclosures.

Our barite and bentonite mining operations, in support of our fluid services business, are subject to regulation by the federal Mine Safety and Health Administration (MSHA) under the Federal Mine Safety and Health Act of 1977 (Mine Act). Information concerning mine safety violations or other regulatory matters required by section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) and the recently proposed Item 106 of Regulation S-K (17 CFR 229.106) is included in Exhibit 99.1 to this annual report.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities.

Halliburton Company's common stock is traded on the New York Stock Exchange. Information related to the high and low market prices of common stock and quarterly dividend payments is included under the caption "Quarterly Data and Market Price Information" on page 105 of this annual report. Cash dividends on common stock in the amount of $0.09 per share were paid in March, June, September, and December of 2010 and 2009. Our Board of Directors intends to consider the payment of quarterly dividends on the outstanding shares of our common stock in the future. The declaration and payment of future dividends, however, will be at the discretion of the Board of Directors and will depend upon, among other things, future earnings, general financial condition and liquidity, success in business activities, capital requirements, and general business conditions.

The following graph and table compare total shareholder return on our common stock for the five-year period ended December 31, 2010, with the Standard & Poor's 500 Stock Index and the Standard & Poor's Energy Composite Index over the same period. This comparison assumes the investment of $100 on December 31, 2005, and the reinvestment of all dividends. The shareholder return set forth is not necessarily indicative of future performance.

	December 31					
	2005	2006	2007	2008	2009	2010
Halliburton	$ 100.00	$ 101.11	$ 124.70	$ 60.53	$ 101.83	$ 139.80
Standard & Poor's 500 Stock Index	100.00	115.80	122.16	76.96	97.33	111.99
Standard & Poor's Energy Composite Index	100.00	124.21	166.94	108.73	123.76	149.08

At February 11, 2011, there were 17,222 shareholders of record. In calculating the number of shareholders, we consider clearing agencies and security position listings as one shareholder for each agency or listing.

Following is a summary of repurchases of our common stock during the three-month period ended December 31, 2010.

Period	Total Number of Shares Purchased (a)		Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs
October 1-31	35,441	$	34.13	–
November 1-30	20,884	$	34.19	–
December 1-31	106,346	$	40.00	–
Total	162,671	$	37.97	–

(a) All of the 162,671 shares purchased during the three-month period ended December 31, 2010 were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting in restricted stock grants. These shares were not part of a publicly announced program to purchase common shares.

Item 6. Selected Financial Data.

Information related to selected financial data is included on page 104 of this annual report.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation.

Information related to Management's Discussion and Analysis of Financial Condition and Results of Operations is included on pages 33 through 58 of this annual report.

Item 7(a). Quantitative and Qualitative Disclosures About Market Risk.

Information related to market risk is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Financial Instrument Market Risk" on page 57 of this annual report.

Item 8. Financial Statements and Supplementary Data.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.
None.

Item 9(a). Controls and Procedures.
In accordance with the Securities Exchange Act of 1934 Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2010 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.
There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.
See page 59 for Management's Report on Internal Control Over Financial Reporting and page 60 for Report of Independent Registered Public Accounting Firm on its assessment of our internal control over financial reporting.

Item 9(b). Other Information.
None.

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

EXECUTIVE OVERVIEW

Organization
We are a leading provider of products and services to the energy industry. We serve the upstream oil and natural gas industry throughout the lifecycle of the reservoir, from locating hydrocarbons and managing geological data, to drilling and formation evaluation, well construction and completion, and optimizing production through the life of the field. Activity levels within our operations are significantly impacted by spending on upstream exploration, development, and production programs by major, national, and independent oil and natural gas companies. We report our results under two segments, Completion and Production and Drilling and Evaluation:
- our Completion and Production segment delivers cementing, stimulation, intervention, pressure control, and completion services. The segment consists of production enhancement services, completion tools and services, cementing services, and Boots & Coots; and
- our Drilling and Evaluation segment provides field and reservoir modeling, drilling, evaluation, and precise wellbore placement solutions that enable customers to model, measure, and optimize their well construction activities. The segment consists of fluid services, drilling services, drill bits, wireline and perforating services, testing and subsea, software and asset solutions, and integrated project management and consulting services.

The business operations of our segments are organized around four primary geographic regions: North America, Latin America, Europe/Africa/CIS, and Middle East/Asia. We have significant manufacturing operations in various locations, including, but not limited to, the United States, Canada, the United Kingdom, Malaysia, Mexico, Brazil, and Singapore. With approximately 58,000 employees, we operate in approximately 80 countries around the world and our corporate headquarters are in Houston, Texas and Dubai, United Arab Emirates.

Financial results
During 2010, we produced revenue of $18.0 billion and operating income of $3.0 billion, reflecting an operating margin of 17%. Revenue increased $3.3 billion, or 22% from 2009, while operating income increased $1.0 billion, or 51% from 2009. Overall, these increases were due to our customers' higher capital spending throughout 2010, led by increased drilling activity and pricing improvements in North America.

Business outlook
We continue to believe in the strength of the long-term fundamentals of our business. Although we saw significant improvements in our business during 2010, the ongoing concerns about global economic recovery and the Gulf of Mexico/Macondo well incident, including the related reduction in deepwater drilling activity in the United States Gulf of Mexico, may cause the near-term growth for our business to be at a more moderate pace.

During 2010, we saw a rebound in United States land rig count and drilling activity driven by a surge in horizontal drilling and activity in oil and liquids-rich unconventional plays. The trend toward more service-intensive work has resulted in absorption of much of the industry's excess oilfield equipment capacity. Due to this absorption of excess capacity and our equipment utilization rates surpassing peak levels experienced in the third quarter of 2008, we continue to see price and margin improvements over the prior year for most of our products and services. Our fourth quarter 2010 Gulf of Mexico business declined sharply from the third quarter 2010 as the company felt the full impact of the deepwater drilling suspension. The drilling suspension was lifted in the fourth quarter of 2010, but we believe prospects for a recovery in the Gulf of Mexico will remain uncertain through the first half, and perhaps the full year, of 2011. Despite weaker natural gas fundamentals and uncertainty in the Gulf of Mexico recovery, we believe our North America revenues and margins are likely sustainable through 2011.

Outside of North America, revenues remained essentially flat while our 2010 operating income declined from 2009 levels due to highly competitive pricing and an unfavorable activity mix. However, we expect the global demand growth will have a moderate recovery as international rig count increases with macroeconomic trends supporting higher operator spending. On a longer term basis, we expect the global economic recovery to accelerate, which we believe will lead to absorption of the industry's spare capacity and improved international pricing.

Based on trends we see for future demand for our business, we are executing several key initiatives in 2011. These initiatives involve increasing manufacturing production in the Eastern Hemisphere, improving service delivery in North America, and building a new technology center in Houston. We intend to update the progress of these investments throughout the year, but we expect that costs associated with these initiatives will impact first quarter 2011 results by approximately $0.02 per share.

Our operating performance and business outlook are described in more detail in "Business Environment and Results of Operations."

Gulf of Mexico/Macondo well incident

On April 22, 2010, the semisubmersible drilling rig, Deepwater Horizon, sank in the Gulf of Mexico after an explosion and fire onboard the rig that began on April 20, 2010. We performed a variety of services on the Deepwater Horizon, including cementing, mud logging, directional drilling, measurement-while-drilling, and rig data acquisition services. The cause of the explosion, fire, and resulting oil spill is being investigated by numerous industry participants, governmental agencies and Congressional committees, and we have been named in many class action complaints involving pollution damage claims and other lawsuits related to wrongful death and other personal injuries claims. In May 2010, the United States Department of the Interior effectively suspended all offshore deepwater drilling projects in the United States Gulf of Mexico. Despite the fact that the drilling suspension was lifted in October 2010, we have experienced a reduction in our Gulf of Mexico operations since the Macondo well incident and we believe that the prospects for any significant increase in activity will remain uncertain through the first half, and perhaps the full year, of 2011. Longer term, we do not know the extent of the impact on revenue or earnings as they are dependent on, among other things, our customers' actions and the potential movement of deepwater rigs to other markets. For additional information, see "Business Environment and Result of Operations," Note 8 to the consolidated financial statements, Item 3, "Legal Proceedings," and Item 1(a), "Risk Factors."

Financial markets, liquidity, and capital resources

Since mid-2008, the global financial markets have been somewhat volatile. While this has created additional risks for our business, we believe we have invested our cash balances conservatively and secured sufficient financing to help mitigate any near-term negative impact on our operations. For additional information, see “Liquidity and Capital Resources” and “Business Environment and Results of Operations.”

LIQUIDITY AND CAPITAL RESOURCES

We ended 2010 with cash and equivalents of $1.4 billion compared to $2.1 billion at December 31, 2009. We also held $653 million of short-term, United States Treasury securities classified as marketable securities.

Significant sources of cash

Cash flows from operating activities contributed $2.2 billion to cash in 2010.

During 2010, we sold approximately $1.9 billion of short-term marketable securities.

Further available sources of cash. We have an unsecured $1.2 billion, five-year revolving credit facility to provide commercial paper support, general working capital, and credit for other corporate purposes. The facility was undrawn as of December 31, 2010.

Significant uses of cash

Capital expenditures were $2.1 billion in 2010 and were predominantly made in the production enhancement, drilling services, wireline and perforating, and cementing product service lines.

During 2010, we purchased approximately $1.3 billion in short-term marketable securities.

We paid $523 million to acquire various companies, including Boots & Coots, Inc. (Boots & Coots), during 2010 that should enhance or augment our current portfolio of products and services.

In September 2010, we completed the acquisition of Boots & Coots in a stock and cash transaction valued at approximately $248 million, of which approximately $143 million was paid in cash and approximately 3.4 million shares of our common stock were issued to Boots & Coots stockholders. Subsequent to the acquisition, we retired approximately $40 million of Boots & Coots outstanding debt. Effective October 2010, Boots & Coots results of operations were included in our Completion and Production segment.

In October 2010, we retired $750 million principal amount of our 5.5% senior notes with available cash and equivalents.

We paid $327 million in dividends to our shareholders in 2010.

We paid $177 million to United States and Nigerian authorities during 2010 related to KBR TSKJ matters. See Notes 7 and 8 to our consolidated financial statements for more information.

Future uses of cash. Capital spending for 2011 is expected to be approximately $3.0 billion. The capital expenditures plan for 2011 is primarily directed toward our production enhancement, drilling services, wireline and perforating, completion tools, and cementing product service lines.

We are currently exploring opportunities for acquisitions that will enhance or augment our current portfolio of products and services, including those with unique technologies or distribution networks in areas where we do not already have large operations.

Subject to Board of Directors approval, we expect to pay quarterly dividends of approximately $80 million during 2011. We also have approximately $1.7 billion remaining available under our share repurchase authorization, which may be used for open market share purchases.

The following table summarizes our significant contractual obligations and other long-term liabilities as of December 31, 2010:

	Payments Due						
Millions of dollars	2011	2012	2013	2014	2015	Thereafter	Total
Long-term debt	$ –	$ –	$ –	$ –	$ –	$ 3,824	$ 3,824
Interest on debt (a)	263	263	263	263	263	5,359	6,674
Operating leases	161	122	87	50	41	149	610
Purchase obligations (b)	1,714	91	64	13	6	5	1,893
Pension funding obligations (c)	41	–	–	–	–	–	41
Other long-term liabilities	9	9	9	–	–	–	27
Total	$ 2,188	$ 485	$ 423	$ 326	$ 310	$ 9,337	$ 13,069

(a) Interest on debt includes 86 years of interest on $300 million of debentures at 7.6% interest that become due in 2096.
(b) Primarily represents certain purchase orders for goods and services utilized in the ordinary course of our business.
(c) Amount based on assumptions that are subject to change. Also, we may choose to make additional discretionary contributions. We are currently not able to reasonably estimate our contributions for years after 2011. See Note 13 to the consolidated financial statements for further information regarding pension contributions.

We had $209 million of gross unrecognized tax benefits at December 31, 2010, of which we estimate $59 million may require a cash payment. We estimate that the total $59 million will not be settled within the next 12 months. We are not able to reasonably estimate in which future periods this amount will ultimately be settled and paid.

Other factors affecting liquidity

Guarantee agreements. In the normal course of business, we have agreements with financial institutions under which approximately $1.5 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2010, including $210 million of surety bonds related to Venezuela. See "Business Environment and Results of Operations – International Operations" for further discussion related to Venezuela. In addition, $52 million of the total $1.5 billion relates to KBR letters of credit, bank guarantees, or surety bonds that are being guaranteed by us in favor of KBR's customers and lenders. KBR has agreed to compensate us for these guarantees and indemnify us if we are required to perform under any of these guarantees. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization.

Financial position in current market. We believe our $1.4 billion of cash and equivalents and $653 million in investments in marketable securities as of December 31, 2010 provide sufficient liquidity and flexibility, given the current market environment. Our debt maturities extend over a long period of time. We currently have a total of $1.2 billion of committed bank credit under our revolving credit facility to support our operations and any commercial paper we may issue in the future. We have no financial covenants or material adverse change provisions in our bank agreements. Currently, there are no borrowings under the revolving credit facility. Although a portion of earnings from our foreign subsidiaries is reinvested overseas indefinitely, we do not consider this to have a significant impact on our liquidity.

In addition, we manage our cash investments by investing principally in United States Treasury securities and repurchase agreements collateralized by United States Treasury securities.

Credit ratings. Credit ratings for our long-term debt remain A2 with Moody's Investors Service and A with Standard & Poor's. The credit ratings on our short-term debt remain P-1 with Moody's Investors Service and A-1 with Standard & Poor's.

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Customer receivables. In line with industry practice, we bill our customers for our services in arrears and are, therefore, subject to our customers delaying or failing to pay our invoices. In weak economic environments, we may experience increased delays and failures to pay our invoices due to, among other reasons, a reduction in our customers' cash flow from operations and their access to the credit markets. For example, we have seen a delay in receiving payment on our receivables from one of our primary customers in Venezuela. If our customers delay in paying or fail to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

BUSINESS ENVIRONMENT AND RESULTS OF OPERATIONS

We operate in approximately 80 countries throughout the world to provide a comprehensive range of discrete and integrated services and products to the energy industry. The majority of our consolidated revenue is derived from the sale of services and products to major, national, and independent oil and natural gas companies worldwide. We serve the upstream oil and natural gas industry throughout the lifecycle of the reservoir, from locating hydrocarbons and managing geological data, to drilling and formation evaluation, well construction and completion, and optimizing production throughout the life of the field. Our two business segments are the Completion and Production segment and the Drilling and Evaluation segment. The industries we serve are highly competitive with many substantial competitors in each segment. In 2010, based upon the location of the services provided and products sold, 46% of our consolidated revenue was from the United States. In 2009, 36% of our consolidated revenue was from the United States. No other country accounted for more than 10% of our revenue during these periods.

Operations in some countries may be adversely affected by unsettled political conditions, acts of terrorism, civil unrest, force majeure, war or other armed conflict, expropriation or other governmental actions, inflation, exchange control problems, and highly inflationary currencies. We believe the geographic diversification of our business activities reduces the risk that loss of operations in any one country would be materially adverse to our consolidated results of operations.

Activity levels within our business segments are significantly impacted by spending on upstream exploration, development, and production programs by major, national, and independent oil and natural gas companies. Also impacting our activity is the status of the global economy, which impacts oil and natural gas consumption.

Some of the more significant barometers of current and future spending levels of oil and natural gas companies are oil and natural gas prices, the world economy, the availability of credit, and global stability, which together drive worldwide drilling activity. Our financial performance is significantly affected by oil and natural gas prices and worldwide rig activity, which are summarized in the following tables.

This table shows the average oil and natural gas prices for West Texas Intermediate (WTI), United Kingdom Brent crude oil, and Henry Hub natural gas:

Average Oil Prices (dollars per barrel)	2010	2009	2008
West Texas Intermediate	$ 79.36	$ 61.65	$ 99.37
United Kingdom Brent	$ 79.66	$ 61.49	$ 96.86
Average United States Gas Prices (dollars per thousand cubic feet, or mcf)			
Henry Hub	$ 4.52	$ 4.06	$ 9.13

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The historical yearly average rig counts based on the Baker Hughes Incorporated rig count information were as follows:

Land vs. Offshore	2010	2009	2008
United States:			
Land	1,509	1,042	1,812
Offshore (incl. Gulf of Mexico)	32	44	65
Total	1,541	1,086	1,877
Canada:			
Land	349	220	378
Offshore	2	1	1
Total	351	221	379
International (excluding Canada):			
Land	789	722	784
Offshore	305	275	295
Total	1,094	997	1,079
Worldwide total	2,986	2,304	3,335
Land total	2,647	1,984	2,974
Offshore total	339	320	361

Oil vs. Natural Gas	2010	2009	2008
United States (incl. Gulf of Mexico):			
Oil	593	282	384
Natural Gas	948	804	1,493
Total	1,541	1,086	1,877
Canada:			
Oil	201	102	160
Natural Gas	150	119	219
Total	351	221	379
International (excluding Canada):			
Oil	840	776	825
Natural Gas	254	221	254
Total	1,094	997	1,079
Worldwide total	2,986	2,304	3,335
Oil total	1,634	1,160	1,369
Natural Gas total	1,352	1,144	1,966

Drilling Type	2010	2009	2008
United States (incl. Gulf of Mexico):			
Horizontal	822	456	552
Vertical	501	433	953
Directional	218	197	372
Total	1,541	1,086	1,877

Our customers’ cash flows, in most instances, depend upon the revenue they generate from the sale of oil and natural gas. Lower oil and natural gas prices usually translate into lower exploration and production budgets. The opposite is true for higher oil and natural gas prices.

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During the latter portion of 2008 and throughout much of 2009, there was an unprecedented decline in oil and natural gas prices and demand for our services due to the worldwide recession. Since then, oil prices have rebounded. According to the International Energy Agency's (IEA) January 2011 "Oil Market Report," 2011 world petroleum demand is forecasted to increase 2% over 2010 levels. Emerging economies continue to be a significant factor in the recovery, while mature economies play a lesser role. The outlook thus faces uncertainties, as the global recovery continues to remain somewhat fragile. However, we believe that, over the long term, any major macroeconomic disruptions may ultimately correct themselves as the underlying trends of smaller and more complex reservoirs, high depletion rates, and the need for continual reserve replacement should drive the long-term need for our services.

North America operations

Volatility in oil and natural gas prices can impact our customers' drilling and production activities. In 2009, the region experienced an unprecedented decline in rig count and drilling activity primarily due to a decline in natural gas prices. During 2010, drilling activity has significantly improved. There has also been a shift to oil and liquids-rich activity which has helped to drive increased service intensity because of horizontal drilling and completions complexity. As of December 31, 2010, rig counts had increased approximately 42% from the end of 2009. Current horizontal rigs represent over 50% of total rigs in the United States and are about 49% higher than the levels at the peak rig count of third quarter 2008. These trends have led to increased demand and improved pricing for most of our products and services in our United States land operations. In the fourth quarter of 2010, North America revenue and operating income increased 10% sequentially, outpacing the United States rig count growth of 4%. Going forward, we expect that the overall rig count will continue to grow, but at a slower rate. We also expect further pricing opportunities from our already high utilization rate; however, growing cost pressure will serve to somewhat slow down the rate of improvement in our margins.

Gulf of Mexico/Macondo well incident. The semisubmersible drilling rig, Deepwater Horizon, sank in the Gulf of Mexico on April 22, 2010 after an explosion and fire onboard the rig that began on April 20, 2010. We performed a variety of services on the Deepwater Horizon, including cementing, mud logging, directional drilling, measurement-while-drilling, and rig data acquisition services. The cause of the explosion, fire, and resulting oil spill is being investigated by numerous industry participants, congressional committees, and governmental agencies, including the United States Coast Guard and the BOE (formerly known as the Minerals Management Service), who share jurisdiction over the investigation, the Chemical Safety Board, the National Academy of Science and the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission) established by the President of the United States. For additional information, see Item 3, "Legal Proceedings." In May 2010, the United States Department of the Interior effectively suspended all offshore deepwater drilling projects in the United States Gulf of Mexico. The suspension was lifted in October 2010. Since that time the Department of the Interior has issued guidance and regulations for drillers that intend to resume deepwater drilling activity. There has been no material increase in the level of drilling activity in the Gulf of Mexico since the suspension was lifted. The Department of the Interior's regulations focus in part on increased safety and environmental issues, drilling equipment, and the requirement that operators submit drilling applications demonstrating regulatory compliance with respect to, among other things, required independent third-party inspections, certification of well design and well control equipment and emergency response plans in the event of a blowout.

We are assessing our plans in light of the Macondo well incident relating to the Deepwater Horizon and the current and prospective regulatory response, including any temporary or permanent BOE rules. For the past two quarters we have engaged in discussions with our customers in the Gulf of Mexico and relocated equipment and personnel to other markets. Our business in the Gulf of Mexico represented approximately 12% of our North America revenue in 2008, approximately 16% in 2009, and approximately 9% in 2010, and approximately 5% of our consolidated revenue in 2008, approximately 6% in 2009 and approximately 4% in 2010. Historically, approximately 30% of our Gulf of Mexico business has been related to deepwater activities. Generally, our average margins in the Gulf of Mexico had been similar to the average of our United States onshore margins over the last three years, though less volatile.

We are adjusting the allocation of our Gulf of Mexico existing assets and/or anticipated capital expenditures to some degree in 2011. Despite the fact that the drilling suspension has been lifted, we have experienced a significant reduction in our Gulf of Mexico operations since the Macondo well incident. We continue to believe that prospects for a recovery in the Gulf of Mexico will remain uncertain through the first half, and perhaps the full year, of 2011. However, we intend to maintain all of our infrastructure and most of our headcount in anticipation of a rebound. Longer term, we do not know the extent of the impact on revenue or earnings, as they are dependent, among other things, on our customers' actions and the potential movement of deepwater rigs to other markets.

International operations

Consistent with our long-term strategy to grow our operations outside of North America, we expect to continue to invest capital in our international operations. During 2009, operating income declined from 2008 levels due to a drop in rig count and the impact of pricing concessions that were renegotiated or given in the contract retendering process. During 2010, revenue outside of North America was essentially flat and operating income decreased 22% when compared to the prior year, primarily due to highly competitive pricing and an unfavorable activity mix.

The pace of international recovery is lagging that of previous cycles at this stage, despite international rig counts exceeding the prior peak reached in September of 2008. One of the contributory factors for the difference is the decline in offshore rig counts that we have seen with the current cycle. Given the service intensity of offshore work, we believe this resulted in a more extensive impact on the industry's revenues, a more significant capacity overhang, and consequently, a more pronounced drop off in pricing. However, we are anticipating that the industry will experience steady volume increases in the coming year as macroeconomic trends support a more favorable operator spending outlook, which we believe will eventually lead to meaningful absorption of equipment supply and result in the ability to begin to improve pricing for our services sometime in later 2011. We continue to believe in the long-term prospects of the international market and will align our business accordingly.

Venezuela. We historically had remeasured our net Bolívar Fuerte-denominated monetary asset position at the official, fixed exchange rate of 2.15 Bolívar Fuerte to United States dollar. In January 2010, the Venezuelan government announced a devaluation of the Bolívar Fuerte under a new two-exchange rate system: a 2.6 Bolívar Fuerte to United States dollar rate for essential products and a 4.3 Bolívar Fuerte to United States dollar rate for non-essential products. In the first quarter of 2010, as a result of the devaluation, we recorded a foreign exchange loss of $31 million, which was not tax deductible in Venezuela. We also recorded $10 million of additional tax expense for local Venezuelan income tax purposes as a result of a taxable gain on our net United States dollar-denominated monetary asset position in the country. In December 2010, the Venezuelan government announced the official, fixed exchange rate will be 4.3 Bolívar Fuerte, eliminating the dual exchange rate scheme implemented in early 2010. This change will be effective January 1, 2011 and should have no impact on us since we have applied the 4.3 Bolívar Fuerte fixed exchange rate since the January 2010 devaluation. We continue to work with our primary customer in Venezuela to resolve outstanding issues regarding the payment of invoices in relation to exchange rates and discounts.

As of December 31, 2010, our total net investment in Venezuela was approximately $183 million. In addition to this amount, we have $210 million of surety bond guarantees outstanding relating to our Venezuelan operations.

Initiatives and recent contract awards

Following is a brief discussion of some of our recent and current initiatives:

- increasing our market share in the more economic, unconventional plays and deepwater markets by leveraging our broad technology offerings to provide value to our customers through integrated solutions and the ability to more efficiently drill and complete their wells;
- exploring opportunities for acquisitions that will enhance or augment our current portfolio of products and services, including those with unique technologies or distribution networks in areas where we do not already have large operations;
- making key investments in technology and capital to accelerate growth opportunities. To that end, we are continuing to push our technology and manufacturing development, as well as our supply chain, closer to our customers in the Eastern Hemisphere, and we are building a new, world class technology center in Houston, Texas;
- improving working capital, operating within our cash flow, and managing our balance sheet to maximize our financial flexibility;
- continuing to seek ways to be one of the most cost efficient service providers in the industry by using our scale and breadth of operations; and
- expanding our business with national oil companies.

Contract wins positioning us to grow our operations over the long term include:

- a contract by ConocoPhillips for directional drilling, logging-while-drilling (LWD) and surface data logging (SDL) services to help develop the high temperature Jasmine discovery in the central North Sea;
- an integrated services contract by ExxonMobil Iraq Ltd. for refurbishment of wells in the West Qurna (Phase 1) field in southern Iraq;
- a multi-million dollar contract with ENI to provide a range of integrated energy services, including wireline logging, perforating, acidizing, and well testing, for the redevelopment of the Zubair field in southern Iraq;
- a letter of intent by Shell Iraq Petroleum Development B.V. for the development of the Majnoon field in southern Iraq. The contract is still subject to final approval by the appropriate Iraqi authorities;
- a deepwater, multi-services contract in Angola valued at approximately $1.3 billion for the provision of cementing, production enhancement, completion tools, wireline, and perforating services;
- a contract valued at approximately $750 million from a major exploration and production company for stimulation services in the Williston basin;
- a two-year contract, plus options, with ConocoPhillips China Inc., valued at approximately $40 million, which includes provisions for directional drilling and logging-while-drilling services on the Peng Lai Development in China's Bohai Bay; and
- frac pack and gravel pack deepwater completions awards in Brazil.

RESULTS OF OPERATIONS IN 2010 COMPARED TO 2009

REVENUE: Millions of dollars	2010	2009	Increase (Decrease)	Percentage Change
Completion and Production	$ 9,997	$ 7,419	$ 2,578	35%
Drilling and Evaluation	7,976	7,256	720	10
Total revenue	$ 17,973	$ 14,675	$ 3,298	22%
By geographic region:				
Completion and Production:				
North America	$ 6,183	$ 3,589	$ 2,594	72%
Latin America	839	887	(48)	(5)
Europe/Africa/CIS	1,797	1,771	26	1
Middle East/Asia	1,178	1,172	6	1
Total	9,997	7,419	2,578	35
Drilling and Evaluation:				
North America	2,644	2,073	571	28
Latin America	1,390	1,294	96	7
Europe/Africa/CIS	2,117	2,177	(60)	(3)
Middle East/Asia	1,825	1,712	113	7
Total	7,976	7,256	720	10
Total revenue by region:				
North America	8,827	5,662	3,165	56
Latin America	2,229	2,181	48	2
Europe/Africa/CIS	3,914	3,948	(34)	(1)
Middle East/Asia	3,003	2,884	119	4

OPERATING INCOME: Millions of dollars	2010	2009	Increase (Decrease)	Percentage Change
Completion and Production	$ 2,032	$ 1,016	$ 1,016	100%
Drilling and Evaluation	1,213	1,183	30	3
Corporate and other	(236)	(205)	(31)	15
Total operating income	$ 3,009	$ 1,994	$ 1,015	51%
By geographic region:				
Completion and Production:				
North America	$ 1,423	$ 272	$ 1,151	423%
Latin America	115	172	(57)	(33)
Europe/Africa/CIS	301	315	(14)	(4)
Middle East/Asia	193	257	(64)	(25)
Total	2,032	1,016	1,016	100
Drilling and Evaluation:				
North America	453	178	275	154
Latin America	175	187	(12)	(6)
Europe/Africa/CIS	283	380	(97)	(26)
Middle East/Asia	302	438	(136)	(31)
Total	1,213	1,183	30	3
Total operating income by region (excluding Corporate and other):				
North America	1,876	450	1,426	317
Latin America	290	359	(69)	(19)
Europe/Africa/CIS	584	695	(111)	(16)
Middle East/Asia	495	695	(200)	(29)

The 22% increase in consolidated revenue in 2010 compared to 2009 was primarily due to higher rig count and increased demand for our products and services in North America. As a result of an approximate 45% increase in average North America rig count during 2010 compared to 2009, we experienced a 56% increase in North America revenue. Revenue outside of North America was 51% of consolidated revenue in 2010 and 61% of consolidated revenue in 2009.

The 51% increase in consolidated operating income compared to 2009 primarily stemmed from improved pricing and increased demand in North America, particularly in our Completion and Production division. Operating income in 2010 was adversely impacted by a $50 million non-cash impairment charge for an oil and gas property in Bangladesh. Operating income in 2009 was unfavorably impacted by a $73 million charge associated with employee separation costs and a $15 million charge related to the settlement of a customer receivable in Venezuela.

Following is a discussion of our results of operations by reportable segment.

Completion and Production increase in revenue compared to 2009 was primarily a result of higher activity in North America. North America revenue increased 72%, primarily due to increased activity in the United States in cementing services and production enhancement. Latin America revenue decreased 5% due to declines in all product service lines from reduced activity in Mexico and Venezuela, partially offset by increased activity in Argentina and Colombia. Europe/Africa/CIS revenue was flat, as price discounts in the United Kingdom and decreased demand for production enhancement services in Europe and the Caspian partially offset higher activity levels across Africa. Middle East/Asia revenue was also flat, as job delays and a decrease in demand for production enhancement services in the Middle East partially offset increased demand for production enhancement services in Southeast Asia. Revenue outside of North America was 38% of total segment revenue in 2010 and 52% of total segment revenue in 2009.

The Completion and Production segment operating income increase compared to 2009 was primarily due to the North America region, where operating income grew by $1.2 billion, largely due to increases in demand for production enhancement and cementing services which benefitted from increased rig count associated with higher horizontal drilling activity and improved pricing. Latin America operating income fell 33%, primarily due to lower activity across all product services lines in Mexico. Europe/Africa/CIS operating income declined 4% from declines in Europe in completion tools and production enhancement services. Middle East/Asia operating income decreased 25% due to activity declines throughout the region.

Drilling and Evaluation revenue increased compared to 2009 primarily as a result of increased activity in North America, where revenue grew 28%. Latin America revenue grew 7% as increased demand for all products and services in Brazil and Colombia was offset by lower activity in Venezuela and lower demand for wireline and perforating services in Mexico. Europe/Africa/CIS revenue was relatively flat for the period, as higher drilling activity and increased demand for drilling fluid services in Norway and the Commonwealth of Independent States (CIS) was offset by lower drilling activity and decreased demand for drilling fluid services throughout Africa. Middle East/Asia revenue rose 7% as increased demand for drilling fluid services in Southeast Asia and the commencement of activity in Iraq offset decreased demand for drilling services throughout most of the region. Revenue outside North America was 67% of total segment revenue in 2010 and 71% of total segment revenue in 2009.

Segment operating income compared to 2009 was relatively flat due to increased activity in North America being offset by lower activity internationally. North America operating income increased $275 million from improved pricing and increased demand for nearly all products and services. Latin America operating income fell 6%, primarily due to lower drilling activity in Mexico. The Europe/Africa/CIS region operating income fell 26% as decreased demand and higher costs for drilling services, wireline and perforating services, and drilling fluid services in Africa offset increased demand for drilling fluid services in Norway. Middle East/Asia operating income decreased 31% due to a $50 million non-cash impairment charge to an oil and gas property in Bangladesh, higher costs throughout most of the region, lower drilling services in Saudi Arabia, and decreased demand for drilling services and wireline and perforating services in most of Asia Pacific.

Corporate and other expenses were $236 million in 2010 compared to $205 million in 2009. The 2009 results included $5 million in employee separation costs. The 15% increase was primarily related to higher legal costs.

NONOPERATING ITEMS

Interest expense, net of interest income increased $12 million in 2010 compared to 2009 primarily due to the issuance of $2 billion in senior notes in March of 2009.

Other, net in 2010 included a $31 million loss on foreign exchange associated with the devaluation of the Venezuelan Bolívar Fuerte.

Income (loss) from discontinued operations, net in 2010 included $62 million of income primarily related to the finalization of a United States tax matter with the Internal Revenue Service and a charge of $17 million, after-tax, related to an indemnity payment on behalf of KBR for a settlement agreement reached with the Federal Government of Nigeria.

RESULTS OF OPERATIONS IN 2009 COMPARED TO 2008

REVENUE: Millions of dollars	2009	2008	Increase (Decrease)	Percentage Change
Completion and Production	$ 7,419	$ 9,610	$ (2,191)	(23)%
Drilling and Evaluation	7,256	8,669	(1,413)	(16)
Total revenue	$ 14,675	$ 18,279	$ (3,604)	(20)%
By geographic region:				
Completion and Production:				
North America	$ 3,589	$ 5,327	$ (1,738)	(33)%
Latin America	887	978	(91)	(9)
Europe/Africa/CIS	1,771	1,938	(167)	(9)
Middle East/Asia	1,172	1,367	(195)	(14)
Total	7,419	9,610	(2,191)	(23)
Drilling and Evaluation:				
North America	2,073	3,013	(940)	(31)
Latin America	1,294	1,447	(153)	(11)
Europe/Africa/CIS	2,177	2,408	(231)	(10)
Middle East/Asia	1,712	1,801	(89)	(5)
Total	7,256	8,669	(1,413)	(16)
Total revenue by region:				
North America	5,662	8,340	(2,678)	(32)
Latin America	2,181	2,425	(244)	(10)
Europe/Africa/CIS	3,948	4,346	(398)	(9)
Middle East/Asia	2,884	3,168	(284)	(9)

OPERATING INCOME: Millions of dollars	2009	2008	Increase (Decrease)	Percentage Change
Completion and Production	$ 1,016	$ 2,304	$ (1,288)	(56)%
Drilling and Evaluation	1,183	1,970	(787)	(40)
Corporate and other	(205)	(264)	59	(22)
Total operating income	$ 1,994	$ 4,010	$ (2,016)	(50)%
By geographic region:				
Completion and Production:				
North America	$ 272	$ 1,426	$ (1,154)	(81)%
Latin America	172	214	(42)	(20)
Europe/Africa/CIS	315	360	(45)	(13)
Middle East/Asia	257	304	(47)	(15)
Total	1,016	2,304	(1,288)	(56)
Drilling and Evaluation:				
North America	178	679	(501)	(74)
Latin America	187	307	(120)	(39)
Europe/Africa/CIS	380	497	(117)	(24)
Middle East/Asia	438	487	(49)	(10)
Total	1,183	1,970	(787)	(40)
Total operating income by region (excluding Corporate and other):				
North America	450	2,105	(1,655)	(79)
Latin America	359	521	(162)	(31)
Europe/Africa/CIS	695	857	(162)	(19)
Middle East/Asia	695	791	(96)	(12)

The 20% decline in consolidated revenue in 2009 compared to 2008 was primarily due to pricing declines and lower demand for our products and services in North America due to a significant reduction in rig count. As a result of an approximate 42% reduction in average rig count in North America during 2009 compared to 2008, we experienced a 32% decline in North America revenue from 2008. Revenue outside of North America was 61% of consolidated revenue in 2009 and 54% of consolidated revenue in 2008.

The decrease in consolidated operating income compared to 2008 primarily stemmed from a 79% decrease in North America due to a decline in rig count and severe margin contraction, a $73 million charge associated with employee separation costs, and a $15 million charge related to the settlement of a customer receivable in Venezuela. Operating income in 2008 was favorably impacted by a $35 million gain on the sale of a joint venture interest in the United States, a combined $25 million gain related to the sale of two investments in the United States, and a net $5 million gain on the settlement of two patent disputes. Operating income in 2008 was adversely impacted by approximately $52 million as a result of hurricanes in the Gulf of Mexico, a $23 million impairment charge related to an oil and natural gas property in Bangladesh, and a $22 million acquisition-related charge for WellDynamics.

Following is a discussion of our results of operations by reportable segment.

Completion and Production decrease in revenue compared to 2008 was primarily a result of overall pricing declines and lower demand for our products and services in North America. More specifically, North America revenue fell 33% as a result of pricing declines and a drop in demand for production enhancement services and cementing services. Latin America revenue decreased 9% as increased activity for all product service lines in Mexico and Colombia was outweighed by lower activity across all product service lines in Venezuela and Argentina. Europe/Africa/CIS revenue decreased 9% on lower demand for completion tools and services in Africa. In addition, production enhancement services in Europe were negatively impacted by job delays in the North Sea. Middle East/Asia revenue fell 14% due to job delays and a decrease in demand for all products and services in the Middle East. Revenue outside of North America was 52% of total segment revenue in 2009 and 45% of total segment revenue in 2008.

The Completion and Production segment operating income decrease compared to 2008 was primarily due to the North America region, where operating income fell 81% largely due to pricing declines and significant reductions in rig count resulting in lower demand for our products and services. Results in 2009 were adversely impacted by $34 million in employee separation costs. In 2008, North America was negatively impacted by approximately $25 million due to Gulf of Mexico hurricanes but benefited from a $35 million gain on the sale of a joint venture interest. Latin America operating income decreased 20% driven by lower activity across all product service lines in Venezuela and Argentina. Europe/Africa/CIS operating income decreased 13% as improved cost management and higher demand for cementing services across the region were outweighed by job delays and lower demand for completion tools and services in Africa and production enhancement services in the North Sea and Angola. Middle East/Asia operating income decreased 15% primarily due to lower completion tools sales in Saudi Arabia and lower demand for production enhancement services in Oman and Malaysia.

Drilling and Evaluation revenue decrease compared to 2008 was primarily a result of pricing declines and decreased demand for our products and services stemming from a reduction in rig count in North America, where revenue fell 31%. Latin America revenue fell 11% as increased drilling activity in Brazil was outweighed by lower demand for all product service lines in Venezuela, Argentina, and Colombia. Europe/Africa/CIS revenue decreased 10% as increases in software sales and consulting services in Algeria were offset by decreased demand for drilling fluids services in Nigeria and Angola and drilling services in Europe. Pricing pressure also had a significant impact on revenue in Europe and Russia. Middle East/Asia revenue decreased 5% as increased demand for drilling fluid services and testing and subsea services in Asia Pacific were outweighed by lower drilling activity in the Middle East and declines in software sales and consulting services and wireline and perforating services in Asia Pacific. Revenue outside of North America was 71% of total segment revenue in 2009 and 65% of total segment revenue in 2008.

The decrease in segment operating income compared to 2008 was primarily due to a 74% decrease in North America operating income related to pricing declines and rig count reductions. Results in 2009 were also adversely impacted by $34 million in employee separation costs. In 2008, this segment's results were negatively impacted by approximately $27 million due to Gulf of Mexico hurricanes and a $23 million impairment charge related to an oil and natural gas property in Bangladesh, but benefited from $25 million of gains related to the sale of two investments in the United States. Latin America operating income fell 39% primarily due to lower activity across all product service lines in Venezuela and decreased demand and pricing pressure for drilling services and wireline and perforating services in Argentina, Colombia, and Mexico. The region was also adversely affected by a $12 million charge related to the settlement of a customer receivable in Venezuela. The Europe/Africa/CIS region operating income fell 24% as increased demand for drilling fluid services in Norway and Kazakhstan and increased software sales and consulting services in Africa were outweighed by pricing pressures and decreased drilling activity in Europe and lower demand for drilling fluid services in Africa. Middle East/Asia operating income decreased 10% over 2008 as declines in drilling activity in Saudi Arabia and China outweighed an increase in software sales and consulting services in the Middle East and higher demand for testing and subsea services in Asia. This region was negatively impacted by the impairment charge related to an oil and natural gas property in Bangladesh in 2008.

Corporate and other expenses were $205 million in 2009 compared to $264 million in 2008. The 2009 results include $5 million in employee separation costs. The 22% reduction was primarily attributable to our 2009 focus on reducing discretionary spending and optimizing headcount and a $22 million acquisition-related charge for WellDynamics related to employee incentive compensation awards in 2008. 2008 also included a net $5 million gain on the settlement of two patent disputes.

NONOPERATING ITEMS

Interest expense, net of interest income increased $157 million in 2009 compared to 2008 primarily due to the issuance of $2 billion in senior notes during the first quarter of 2009, partially offset by the redemption of our convertible senior notes early in the third quarter of 2008.

Income (loss) from discontinued operations, net of income tax benefit in 2008 included $420 million in charges reflecting the resolution of the DOJ and SEC FCPA investigations and the impact of our assumption changes during that period regarding the resolution of the Barracuda-Caratinga bolt arbitration matter under the indemnities and guarantees provided to KBR upon separation.

Noncontrolling interest in net income of subsidiaries increased $19 million compared to 2008, primarily related to the impact of a change in effective ownership of a joint venture in 2008.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the use of judgments and estimates. Our critical accounting policies are described below to provide a better understanding of how we develop our assumptions and judgments about future events and related estimations and how they can impact our financial statements. A critical accounting estimate is one that requires our most difficult, subjective, or complex estimates and assessments and is fundamental to our results of operations. We identified our most critical accounting estimates to be:

- forecasting our effective income tax rate, including our future ability to utilize foreign tax credits and the realizability of deferred tax assets, and providing for uncertain tax positions;
- legal and investigation matters;
- valuations of indemnities;
- valuations of long-lived assets, including intangible assets;
- purchase price allocation for acquired businesses;
- pensions;
- allowance for bad debts; and
- percentage-of-completion accounting for long-term, construction-type contracts.

We base our estimates on historical experience and on various other assumptions we believe to be reasonable according to the current facts and circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. We believe the following are the critical accounting policies used in the preparation of our consolidated financial statements, as well as the significant estimates and judgments affecting the application of these policies. This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in this report.

We have discussed the development and selection of these critical accounting policies and estimates with the Audit Committee of our Board of Directors, and the Audit Committee has reviewed the disclosure presented below.

Income tax accounting

We recognize the amount of taxes payable or refundable for the current year and use an asset and liability approach in recognizing the amount of deferred tax liabilities and assets for the future tax consequences of events that have been recognized in our financial statements or tax returns. We apply the following basic principles in accounting for our income taxes:

- a current tax liability or asset is recognized for the estimated taxes payable or refundable on tax returns for the current year;
- a deferred tax liability or asset is recognized for the estimated future tax effects attributable to temporary differences and carryforwards;
- the measurement of current and deferred tax liabilities and assets is based on provisions of the enacted tax law, and the effects of potential future changes in tax laws or rates are not considered; and
- the value of deferred tax assets is reduced, if necessary, by the amount of any tax benefits that, based on available evidence, are not expected to be realized.

We determine deferred taxes separately for each tax-paying component (an entity or a group of entities that is consolidated for tax purposes) in each tax jurisdiction. That determination includes the following procedures:

- identifying the types and amounts of existing temporary differences;
- measuring the total deferred tax liability for taxable temporary differences using the applicable tax rate;
- measuring the total deferred tax asset for deductible temporary differences and operating loss carryforwards using the applicable tax rate;
- measuring the deferred tax assets for each type of tax credit carryforward; and
- reducing the deferred tax assets by a valuation allowance if, based on available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Our methodology for recording income taxes requires a significant amount of judgment in the use of assumptions and estimates. Additionally, we use forecasts of certain tax elements, such as taxable income and foreign tax credit utilization, as well as evaluate the feasibility of implementing tax planning strategies. Given the inherent uncertainty involved with the use of such variables, there can be significant variation between anticipated and actual results. Unforeseen events may significantly impact these variables, and changes to these variables could have a material impact on our income tax accounts related to both continuing and discontinued operations.

We have operations in approximately 80 countries other than the United States. Consequently, we are subject to the jurisdiction of a significant number of taxing authorities. The income earned in these various jurisdictions is taxed on differing bases, including income actually earned, income deemed earned, and revenue-based tax withholding. The final determination of our income tax liabilities involves the interpretation of local tax laws, tax treaties, and related authorities in each jurisdiction. Changes in the operating environment, including changes in tax law and currency/repatriation controls, could impact the determination of our income tax liabilities for a tax year.

Tax filings of our subsidiaries, unconsolidated affiliates, and related entities are routinely examined in the normal course of business by tax authorities. These examinations may result in assessments of additional taxes, which we work to resolve with the tax authorities and through the judicial process. Predicting the outcome of disputed assessments involves some uncertainty. Factors such as the availability of settlement procedures, willingness of tax authorities to negotiate, and the operation and impartiality of judicial systems vary across the different tax jurisdictions and may significantly influence the ultimate outcome. We review the facts for each assessment, and then utilize assumptions and estimates to determine the most likely outcome and provide taxes, interest, and penalties as needed based on this outcome. We provide for uncertain tax positions pursuant to current accounting standards, which prescribe a minimum recognition threshold and measurement methodology that a tax position taken or expected to be taken in a tax return is required to meet before being recognized in the financial statements. The standards also provide guidance for derecognition classification, interest and penalties, accounting in interim periods, disclosure, and transition.

Legal and investigation matters

As discussed in Note 8 of our consolidated financial statements, as of December 31, 2010, we have accrued an estimate of the probable and estimable costs for the resolution of some of these legal and investigation matters. For other matters for which the liability is not probable and reasonably estimable, we have not accrued any amounts. Attorneys in our legal department monitor and manage all claims filed against us and review all pending investigations. Generally, the estimate of probable costs related to these matters is developed in consultation with internal and outside legal counsel representing us. Our estimates are based upon an analysis of potential results, assuming a combination of litigation and settlement strategies. The precision of these estimates is impacted by the amount of due diligence we have been able to perform. We attempt to resolve these matters through settlements, mediation, and arbitration proceedings when possible. If the actual settlement costs, final judgments, or fines, after appeals, differ from our estimates, our future financial results may be adversely affected. We have in the past recorded significant adjustments to our initial estimates of these types of contingencies.

Indemnity valuations

We provided indemnification in favor of KBR for certain contingent liabilities related to FCPA investigations and the Barracuda-Caratinga bolts matter. See Note 7 and 8 to the consolidated financial statements for further information. Accounting standards require recognition of third-party indemnities at their inception. Therefore, we recorded our estimate of the fair market value of these indemnities as of the date of KBR’s separation. The initial amounts recorded for the FCPA and Barracuda-Caratinga indemnities were based upon analyses conducted by a third-party valuation expert. The valuation models employed a probability-weighted cost analysis, with certain assumptions based upon the accumulation of data and knowledge of the relevant issues. The accounting standards state that the subsequent measurement of such liabilities should not necessarily be based on fair value. The standards reference accounting for subsequent adjustments to these types of liabilities as you would under the current accounting guidance for contingent liabilities. As such, subsequent adjustments to the indemnities provided to KBR upon separation, including the indemnity relating to the FCPA investigations, have been recorded when the loss is both probable and estimable.

Value of long-lived assets, including intangible assets

We carry a variety of long-lived assets on our balance sheet including property, plant and equipment, goodwill, and other intangibles. We conduct impairment tests on long-lived assets whenever events or changes in circumstances indicate that the carrying value may not be recoverable and intangible assets quarterly. Impairment is the condition that exists when the carrying amount of a long-lived asset exceeds its fair value, and any impairment charge that we record reduces our earnings. We review the carrying value of these assets based upon estimated future cash flows while taking into consideration assumptions and estimates including the future use of the asset, remaining useful life of the asset, and service potential of the asset.

Goodwill is the excess of the cost of an acquired entity over the net of the amounts assigned to assets acquired and liabilities assumed. We test goodwill for impairment annually, during the third quarter, or if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. For purposes of performing the goodwill impairment test our reporting units are the same as our reportable segments, the Completion and Production division and the Drilling and Evaluation division. The impairment test consists of a two-step process. The first step compares the fair value of a reporting unit with its carrying amount, including goodwill, and utilizes a future cash flow analysis based on the estimates and assumptions of our forecasted long-term growth model. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. If the carrying amount of a reporting unit exceeds its fair value, we perform the second step of the goodwill impairment test to measure the amount of the impairment loss, if any. The second step of the goodwill impairment test compares the implied fair value of the reporting unit's goodwill with the carrying amount of that goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination. In other words, the estimated fair value of the reporting unit is allocated to all of the assets and liabilities of that unit (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination and the fair value of the reporting unit was the purchase price paid. If the carrying amount of the reporting unit's goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. Any impairment charge that we record reduces our earnings. The fair value of each of our reporting units exceeded its carrying amount by a significant margin for 2010, 2009, and 2008. See Note 1 to the consolidated financial statements for accounting policies related to long-lived assets and intangible assets.

Acquisitions-purchase price allocation

We allocate the purchase price of an acquired business to its identifiable assets and liabilities based on estimated fair values. The excess of the purchase price over the amount allocated to the assets and liabilities, if any, is recorded as goodwill. We use all available information to estimate fair values including quoted market prices, the carrying value of acquired assets, and widely accepted valuation techniques such as discounted cash flows. We engage third-party appraisal firms to assist in fair value determination of inventory, identifiable intangible assets, and any other significant assets or liabilities when appropriate. The judgments made in determining the estimated fair value assigned to each class of assets acquired and liabilities assumed, as well as asset lives, can materially impact our results of operations.

Pensions

Our pension benefit obligations and expenses are calculated using actuarial models and methods. Two of the more critical assumptions and estimates used in the actuarial calculations are the discount rate for determining the current value of benefit obligations and the expected long-term rate of return on plan assets used in determining net periodic benefit cost. Other critical assumptions and estimates used in determining benefit obligations and cost, including demographic factors such as retirement age, mortality, and turnover, are also evaluated periodically and updated accordingly to reflect our actual experience.

Discount rates are determined annually and are based on the prevailing market rate of a portfolio of high-quality debt instruments with maturities matching the expected timing of the payment of the benefit obligations. Expected long-term rates of return on plan assets are determined annually and are based on an evaluation of our plan assets and historical trends and experience, taking into account current and expected market conditions. Plan assets are comprised primarily of equity and debt securities. As we have both domestic and international plans, these assumptions differ based on varying factors specific to each particular country or economic environment.

The weighted-average discount rate utilized in 2010 to determine the projected benefit obligation at the measurement date for our qualified United States continuing pension plans was 4.9%, compared to 5.5% in 2009. The discount rate utilized in 2010 to determine the projected benefit obligation at the measurement date for our United Kingdom pension plan, which constituted 74% of our international plans' pension obligations and 66% of our entire pension obligation, was 5.5%, compared to a discount rate of 5.9% utilized in 2009. The expected long-term rate of return assumption used for determining 2010 and 2009 net periodic pension expense for our qualified United States pension plans was 8.0%. The expected long-term rate of return assumption used for our United Kingdom pension plan expense was 6.7% in 2010 and 6.5% in 2009. The following table illustrates the sensitivity to changes in certain assumptions, holding all other assumptions constant, for the United Kingdom pension plan.

	Effect on	
Millions of dollars	Pretax Pension Expense in 2010	Pension Benefit Obligation at December 31, 2010
25-basis-point decrease in discount rate	$ 1	$ 38
25-basis-point increase in discount rate	$ (1)	$ (35)
25-basis-point decrease in expected long-term rate of return	$ 1	NA
25-basis-point increase in expected long-term rate of return	$ (1)	NA

Our defined benefit plans reduced pretax income by $32 million in 2010, $36 million in 2009, and $48 million in 2008. Included in these amounts was income from expected pension returns of $50 million in 2010, $45 million in 2009, and $51 million in 2008. Actual returns on plan assets totaled $80 million in 2010, compared to $121 million in 2009. Our net actuarial loss, net of tax, related to pension plans at December 31, 2010 was $208 million. In our international plans where employees continue to earn additional benefits for continued service, actuarial gains and losses are being recognized in operating income over a period of nine to 18 years, which represents the estimated average remaining service of the participant group expected to receive benefits. In our international plans where benefits are not accrued for continued service, actuarial gains and losses are being recognized in operating income over a period of two to 36 years, which represents the estimated average remaining lifetime of the benefit obligations. The broad range of two to 36 years reflects varying maturity levels among these plans.

During 2010, we made contributions of $33 million to fund our defined benefit plans. We expect to make contributions of approximately $41 million to our defined benefit plans in 2011.

The actuarial assumptions used in determining our pension benefit obligations may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, and longer or shorter life spans of participants. While we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions may materially affect our financial position or results of operations. See Note 13 to the consolidated financial statements for further information related to defined benefit and other postretirement benefit plans.

Allowance for bad debts

We evaluate our accounts receivable through a continuous process of assessing our portfolio on an individual customer and overall basis. This process consists of a thorough review of historical collection experience, current aging status of the customer accounts, financial condition of our customers, and whether the receivables involve retainages. We also consider the economic environment of our customers, both from a marketplace and geographic perspective, in evaluating the need for an allowance. Based on our review of these factors, we establish or adjust allowances for specific customers and the accounts receivable portfolio as a whole. This process involves a high degree of judgment and estimation, and frequently involves significant dollar amounts. Accordingly, our results of operations can be affected by adjustments to the allowance due to actual write-offs that differ from estimated amounts. Our estimates of allowances for bad debts have historically been accurate. Over the last five years, our estimates of allowances for bad debts, as a percentage of notes and accounts receivable before the allowance, have ranged from 1.5% to 3.0%. At December 31, 2010, allowance for bad debts totaled $91 million or 2.3% of notes and accounts receivable before the allowance, and at December 31, 2009, allowance for bad debts totaled $90 million or 3.0% of notes and accounts receivable before the allowance. A 1% change in our estimate of the collectability of our notes and accounts receivable balance as of December 31, 2010 would have resulted in a $40 million adjustment to 2010 total operating costs and expenses. See Note 3 to the consolidated financial statements for further information.

Percentage of completion

Revenue from certain long-term, integrated project management contracts to provide well construction and completion services is reported on the percentage-of-completion method of accounting. This method of accounting requires us to calculate job profit to be recognized in each reporting period for each job based upon our projections of future outcomes, which include:

- estimates of the total cost to complete the project;
- estimates of project schedule and completion date;
- estimates of the extent of progress toward completion; and
- amounts of any probable unapproved claims and change orders included in revenue.

Progress is generally based upon physical progress related to contractually defined units of work. At the outset of each contract, we prepare a detailed analysis of our estimated cost to complete the project. Risks related to service delivery, usage, productivity, and other factors are considered in the estimation process. Our project personnel periodically evaluate the estimated costs, claims, change orders, and percentage of completion at the project level. The recording of profits and losses on long-term contracts requires an estimate of the total profit or loss over the life of each contract. This estimate requires consideration of total contract value, change orders, and claims, less costs incurred and estimated costs to complete. Anticipated losses on contracts are recorded in full in the period in which they become evident. Profits are recorded based upon the total estimated contract profit times the current percentage complete for the contract.

When calculating the amount of total profit or loss on a long-term contract, we include unapproved claims as revenue when the collection is deemed probable based upon the four criteria for recognizing unapproved claims under current accounting standards. Including probable unapproved claims in this calculation increases the operating income (or reduces the operating loss) that would otherwise be recorded without consideration of the probable unapproved claims. Probable unapproved claims are recorded to the extent of costs incurred and include no profit element. In all cases, the probable unapproved claims included in determining contract profit or loss are less than the actual claim that will be or has been presented to the customer.

At least quarterly, significant projects are reviewed in detail by senior management. There are many factors that impact future costs, including but not limited to weather, inflation, labor and community disruptions, timely availability of materials, productivity, and other factors as outlined in our Item 1(a), "Risk Factors." These factors can affect the accuracy of our estimates and materially impact our future reported earnings. Currently, long-term contracts accounted for under the percentage-of-completion method of accounting do not comprise a significant portion of our business. However, in the future, we expect our business with national or state-owned oil companies to grow relative to our other business, with these types of contracts likely comprising a more significant portion of our business. See Note 1 to the consolidated financial statements for further information.

OFF BALANCE SHEET ARRANGEMENTS

At December 31, 2010, we had no material off balance sheet arrangements, except for operating leases. For information on our contractual obligations related to operating leases, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Future uses of cash."

FINANCIAL INSTRUMENT MARKET RISK

We are exposed to market risk from changes in foreign currency exchange rates, interest rates, and commodity prices. We selectively manage these exposures through the use of derivative instruments to mitigate our market risk from these exposures. The objective of our risk management strategy is to minimize the volatility from fluctuations in foreign currency rates. Our use of derivative instruments entails the following types of market risk:

- volatility of the currency rates;
- counterparty credit risk;
- time horizon of the derivative instruments; and
- the type of derivative instruments used.

We do not use derivative instruments for trading purposes. We do not consider any of these risk management activities to be material. See Note 1 to the consolidated financial statements for additional information on our accounting policies related to derivative instruments. See Note 12 to the consolidated financial statements for additional disclosures related to financial instruments.

Interest rate risk

We currently do not have any variable-rate, long-term debt that exposes us to interest rate risk.

The following table represents principal amounts of our long-term debt at December 31, 2010 and related weighted average interest rates on the repayment amounts by year of maturity for our long-term debt.

Millions of dollars	2011	2017 and Thereafter	Total
Repayment amount ($US)	$ –	$ 3,834	$ 3,834
Weighted average interest rate on repayment amount	–	6.85%	6.85%

The fair market value of long-term debt was $4.6 billion as of December 31, 2010.

ENVIRONMENTAL MATTERS

We are subject to numerous environmental, legal, and regulatory requirements related to our operations worldwide. For information related to environmental matters, see Note 8 to the consolidated financial statements, Item 1(a), "Risk Factors," and Item 3, "Legal Proceedings–Environmental."

NEW ACCOUNTING PRONOUNCEMENTS

In October 2009, the Financial Accounting Standards Board (FASB) issued an update to existing guidance on revenue recognition for arrangements with multiple deliverables. This update will allow companies to allocate consideration received for qualified separate deliverables using estimated selling price for both delivered and undelivered items when vendor-specific objective evidence or third-party evidence is unavailable. Additional disclosures discussing the nature of multiple element arrangements, the types of deliverables under the arrangements, the general timing of their delivery, and significant factors and estimates used to determine estimated selling prices are required. We adopted this update effective January 1, 2011 for new revenue arrangements entered into or materially modified on or after January 1, 2011. We do not expect the provisions of this update to have a material impact on our consolidated financial statements.

FORWARD-LOOKING INFORMATION

The Private Securities Litigation Reform Act of 1995 provides safe harbor provisions for forward-looking information. Forward-looking information is based on projections and estimates, not historical information. Some statements in this Form 10-K are forward-looking and use words like "may," "may not," "believes," "do not believe," "expects "do not expect," "anticipates," "do not anticipate," and other expressions. We may also provide oral or written forward-looking information in other materials we release to the public. Forward-looking information involves risk and uncertainties and reflects our best judgment based on current information. Our results of operations can be affected by inaccurate assumptions we make or by known or unknown risks and uncertainties. In addition, other factors may affect the accuracy of our forward-looking information. As a result, no forward-looking information can be guaranteed. Actual events and the results of operations may vary materially.

We do not assume any responsibility to publicly update any of our forward-looking statements regardless of whether factors change as a result of new information, future events, or for any other reason. You should review any additional disclosures we make in our press releases and Forms 10-K, 10-Q, and 8-K filed with or furnished to the Securities and Exchange Commission (SEC). We also suggest that you listen to our quarterly earnings release conference calls with financial analysts.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Halliburton Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in the Securities Exchange Act Rule 13a-15(f).

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we conducted an evaluation to assess the effectiveness of our internal control over financial reporting as of December 31, 2010 based upon criteria set forth in the Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, we believe that, as of December 31, 2010, our internal control over financial reporting is effective.

The effectiveness of Halliburton's internal control over financial reporting as of December 31, 2010 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report that is included herein.

HALLIBURTON COMPANY

by

/s/ David J. Lesar	/s/ Mark A. McCollum
David J. Lesar	Mark A. McCollum
Chairman of the Board,	Executive Vice President and
President, and Chief Executive Officer	Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Halliburton Company:

We have audited the accompanying consolidated balance sheets of Halliburton Company and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Halliburton Company and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Halliburton Company's internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 17, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 17, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
Halliburton Company:

We have audited Halliburton Company’s internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Halliburton Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, Halliburton Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Halliburton Company as of December 31, 2010 and 2009, and the related consolidated statements of operations, shareholders’ equity, and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated February 17, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 17, 2011

HALLIBURTON COMPANY
Consolidated Statements of Operations

Millions of dollars and shares except per share data	Year Ended December 31 2010	2009	2008
Revenue:			
Services	$ 13,779	$ 10,832	$ 13,391
Product sales	4,194	3,843	4,888
Total revenue	17,973	14,675	18,279
Operating costs and expenses:			
Cost of services	11,237	9,224	10,079
Cost of sales	3,508	3,255	3,970
General and administrative	229	207	282
Gain on sale of assets, net	(10)	(5)	(62)
Total operating costs and expenses	14,964	12,681	14,269
Operating income	3,009	1,994	4,010
Interest expense, net of interest income of $11, $12, and $39	(297)	(285)	(128)
Other, net	(57)	(27)	(33)
Income from continuing operations before income taxes	2,655	1,682	3,849
Provision for income taxes	(853)	(518)	(1,211)
Income from continuing operations	1,802	1,164	2,638
Income (loss) from discontinued operations, net of income tax benefit of $75, $5, and $3	40	(9)	(423)
Net income	$ 1,842	$ 1,155	$ 2,215
Noncontrolling interest in net income of subsidiaries	(7)	(10)	9
Net income attributable to company	$ 1,835	$ 1,145	$ 2,224
Amounts attributable to company shareholders:			
Income from continuing operations	$ 1,795	$ 1,154	$ 2,647
Income (loss) from discontinued operations, net	40	(9)	(423)
Net income attributable to company	$ 1,835	$ 1,145	$ 2,224
Basic income per share attributable to company shareholders:			
Income from continuing operations	$ 1.98	$ 1.28	$ 3.00
Income (loss) from discontinued operations, net	0.04	(0.01)	(0.48)
Net income per share	$ 2.02	$ 1.27	$ 2.52
Diluted income per share attributable to company shareholders:			
Income from continuing operations	$ 1.97	$ 1.28	$ 2.91
Income (loss) from discontinued operations, net	0.04	(0.01)	(0.46)
Net income per share	$ 2.01	$ 1.27	$ 2.45
Basic weighted average common shares outstanding	908	900	883
Diluted weighted average common shares outstanding	911	902	909

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Balance Sheets

Millions of dollars and shares except per share data	December 31 2010	December 31 2009
Assets		
Current assets:		
Cash and equivalents	$ 1,398	$ 2,082
Receivables (less allowance for bad debts of $91 and $90)	3,924	2,964
Inventories	1,940	1,598
Investments in marketable securities	653	1,312
Current deferred income taxes	257	210
Other current assets	714	472
Total current assets	8,886	8,638
Property, plant, and equipment (net of accumulated depreciation of $6,064 and $5,230)	6,842	5,759
Goodwill	1,315	1,100
Other assets	1,254	1,041
Total assets	$ 18,297	$ 16,538
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 1,139	$ 787
Current maturities of long-term debt	–	750
Accrued employee compensation and benefits	716	514
Deferred revenue	266	215
Other current liabilities	636	623
Total current liabilities	2,757	2,889
Long-term debt	3,824	3,824
Employee compensation and benefits	487	462
Other liabilities	842	606
Total liabilities	7,910	7,781
Shareholders' equity:		
Common shares, par value $2.50 per share – authorized 2,000 shares, issued 1,069 shares and 1,067 shares	2,674	2,669
Paid-in capital in excess of par value	339	411
Accumulated other comprehensive loss	(240)	(213)
Retained earnings	12,371	10,863
Treasury stock, at cost – 159 and 165 shares	(4,771)	(5,002)
Company shareholders' equity	10,373	8,728
Noncontrolling interest in consolidated subsidiaries	14	29
Total shareholders' equity	10,387	8,757
Total liabilities and shareholders' equity	$ 18,297	$ 16,538

See notes to consolidated financial statements.

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HALLIBURTON COMPANY
Consolidated Statements of Shareholders' Equity

Millions of dollars	2010	2009	2008
Balance at January 1	$ 8,757	$ 7,744	$ 6,966
Dividends and other transactions with shareholders	(287)	(144)	(623)
Adoption of new accounting standards	–	–	(703)
Treasury shares issued for acquisition	103	–	–
Comprehensive income:			
Net income	1,842	1,155	2,215
Defined benefit and other postretirement plans adjustments	(27)	2	(106)
Other	(1)	–	(5)
Total comprehensive income	1,814	1,157	2,104
Balance at December 31	$ 10,387	$ 8,757	$ 7,744

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Cash Flows

	Year Ended December 31		
Millions of dollars	2010	2009	2008
Cash flows from operating activities:			
Net income	$ 1,842	$ 1,155	$ 2,215
Adjustments to reconcile net income to net cash from operations:			
Depreciation, depletion, and amortization	1,119	931	738
Payments related to KBR TSKJ matters	(177)	(417)	–
Provision for deferred income taxes, continuing operations	124	274	254
(Income) loss from discontinued operations	(40)	9	423
Other changes:			
Receivables	(902)	869	(670)
Inventories	(331)	232	(368)
Accounts payable	330	(118)	161
Other	247	(529)	(79)
Total cash flows from operating activities	2,212	2,406	2,674
Cash flows from investing activities:			
Capital expenditures	(2,069)	(1,864)	(1,824)
Sales of marketable securities	1,925	300	388
Purchases of marketable securities	(1,282)	(1,620)	–
Acquisitions of business assets, net of cash acquired	(523)	(55)	(652)
Other investing activities	194	154	232
Total cash flows from investing activities	(1,755)	(3,085)	(1,856)
Cash flows from financing activities:			
Proceeds from long-term borrowings, net of offering costs	–	1,975	1,187
Payments on long-term borrowings	(790)	(31)	(2,048)
Dividends to shareholders	(327)	(324)	(319)
Payments to reacquire common stock	(141)	(17)	(507)
Other financing activities	144	67	164
Total cash flows from financing activities	(1,114)	1,670	(1,523)
Effect of exchange rate changes on cash	(27)	(33)	(18)
Increase (decrease) in cash and equivalents	(684)	958	(723)
Cash and equivalents at beginning of year	2,082	1,124	1,847
Cash and equivalents at end of year	$ 1,398	$ 2,082	$ 1,124
Supplemental disclosure of cash flow information:			
Cash payments during the year for:			
Interest	$ 310	$ 251	$ 143
Income taxes	$ 804	$ 485	$ 1,057

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Notes to Consolidated Financial Statements

Note 1. Description of Company and Significant Accounting Policies
Description of Company
Halliburton Company's predecessor was established in 1919 and incorporated under the laws of the State of Delaware in 1924. We are one of the world's largest oilfield services companies. Our two business segments are the Completion and Production segment and the Drilling and Evaluation segment. We provide a comprehensive range of services and products for the exploration, development, and production of oil and natural gas around the world.
Use of estimates
Our financial statements are prepared in conformity with accounting principles generally accepted in the United States, requiring us to make estimates and assumptions that affect:
- the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements; and
- the reported amounts of revenue and expenses during the reporting period.

We believe the most significant estimates and assumptions are associated with the forecasting of our effective income tax rate and the valuation of deferred taxes, legal and environmental reserves, indemnity valuations, long-lived asset valuations, purchase price allocations, pensions, allowance for bad debts, and percentage-of-completion accounting for long-term contracts. Ultimate results could differ from our estimates.
Basis of presentation
The consolidated financial statements include the accounts of our company and all of our subsidiaries that we control or variable interest entities for which we have determined that we are the primary beneficiary. All material intercompany accounts and transactions are eliminated. Investments in companies in which we have significant influence are accounted for using the equity method. If we do not have significant influence, we use the cost method. In 2010, we adopted the provisions of new accounting standards. See Note 14 for further information. All periods presented reflect these changes.
Revenue recognition
Overall. Our services and products are generally sold based upon purchase orders or contracts with our customers that include fixed or determinable prices but do not include right of return provisions or other significant post-delivery obligations. Our products are produced in a standard manufacturing operation, even if produced to our customer's specifications. We recognize revenue from product sales when title passes to the customer, the customer assumes risks and rewards of ownership, collectability is reasonably assured, and delivery occurs as directed by our customer. Service revenue, including training and consulting services, is recognized when the services are rendered and collectability is reasonably assured. Rates for services are typically priced on a per day, per meter, per man-hour, or similar basis.
Software sales. Sales of perpetual software licenses, net of any deferred maintenance and support fees, are recognized as revenue upon shipment. Sales of time-based licenses are recognized as revenue over the license period. Maintenance and support fees are recognized as revenue ratably over the contract period, usually a one-year duration.

Percentage of completion. Revenue from certain long-term, integrated project management contracts to provide well construction and completion services is reported on the percentage-of-completion method of accounting. Progress is generally based upon physical progress related to contractually defined units of work. Physical percent complete is determined as a combination of input and output measures as deemed appropriate by the circumstances. All known or anticipated losses on contracts are provided for when they become evident. Cost adjustments that are in the process of being negotiated with customers for extra work or changes in the scope of work are included in revenue when collection is deemed probable.

Research and development

Research and development costs are expensed as incurred. Research and development costs were $366 million in 2010, $325 million in 2009, and $326 million in 2008.

Cash equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Inventories

Inventories are stated at the lower of cost or market. Cost represents invoice or production cost for new items and original cost less allowance for condition for used material returned to stock. Production cost includes material, labor, and manufacturing overhead. Some domestic manufacturing and field service finished products and parts inventories for drill bits, completion products, and bulk materials are recorded using the last-in, first-out method. The remaining inventory is recorded on the average cost method. We regularly review inventory quantities on hand and record provisions for excess or obsolete inventory based primarily on historical usage, estimated product demand, and technological developments.

Allowance for bad debts

We establish an allowance for bad debts through a review of several factors, including historical collection experience, current aging status of the customer accounts, and financial condition of our customers. Our policy is to write off bad debts when the customer accounts are determined to be uncollectible.

Property, plant, and equipment

Other than those assets that have been written down to their fair values due to impairment, property, plant, and equipment are reported at cost less accumulated depreciation, which is generally provided on the straight-line method over the estimated useful lives of the assets. Accelerated depreciation methods are also used for tax purposes, wherever permitted. Upon sale or retirement of an asset, the related costs and accumulated depreciation are removed from the accounts and any gain or loss is recognized. Planned major maintenance costs are generally expensed as incurred. Expenditures for additions, modifications, and conversions are capitalized when they increase the value or extend the useful life of the asset.

Goodwill and other intangible assets

We record as goodwill the excess purchase price over the fair value of the tangible and identifiable intangible assets acquired. The reported amounts of goodwill for each reporting unit are reviewed for impairment on an annual basis, during the third quarter, and more frequently when negative conditions such as significant current or projected operating losses exist. The annual impairment test for goodwill is a two-step process and involves comparing the estimated fair value of each reporting unit to the reporting unit's carrying value, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered impaired, and the second step of the impairment test is unnecessary. If the carrying amount of a reporting unit exceeds its fair value, the second step of the goodwill impairment test would be performed to measure the amount of impairment loss to be recorded, if any. The second step of the goodwill impairment test compares the implied fair value of the reporting unit's goodwill with the carrying amount of that goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination. In other words, the estimated fair value of the reporting unit is allocated to all of the assets and liabilities of that unit (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination and the fair value of the reporting unit was the purchase price paid. If the carrying amount of the reporting unit's goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. The fair value of each of our reporting units exceeded its carrying amount by a significant margin for 2010, 2009, and 2008. In addition, there were no triggering events that occurred in 2010, 2009, or 2008 requiring us to perform additional impairment reviews.

We amortize other identifiable intangible assets with a finite life on a straight-line basis over the period which the asset is expected to contribute to our future cash flows, ranging from 3 to 20 years. The components of these other intangible assets generally consist of patents, license agreements, non-compete agreements, trademarks, and customer lists and contracts.

Evaluating impairment of long-lived assets

When events or changes in circumstances indicate that long-lived assets other than goodwill may be impaired, an evaluation is performed. For an asset classified as held for use, the estimated future undiscounted cash flows associated with the asset are compared to the asset's carrying amount to determine if a write-down to fair value is required. When an asset is classified as held for sale, the asset's book value is evaluated and adjusted to the lower of its carrying amount or fair value less cost to sell. In addition, depreciation and amortization is ceased while it is classified as held for sale.

Income taxes

We recognize the amount of taxes payable or refundable for the year. In addition, deferred tax assets and liabilities are recognized for the expected future tax consequences of events that have been recognized in the financial statements or tax returns. A valuation allowance is provided for deferred tax assets if it is more likely than not that these items will not be realized.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that we will realize the benefits of these deductible differences, net of the existing valuation allowances.

We recognize interest and penalties related to unrecognized tax benefits within the provision for income taxes on continuing operations in our consolidated statements of operations.

We generally do not provide income taxes on the undistributed earnings of non-United States subsidiaries because such earnings are intended to be reinvested indefinitely to finance foreign activities. These additional foreign earnings could be subject to additional tax if remitted, or deemed remitted, as a dividend; however, it is not practicable to estimate the additional amount, if any, of taxes payable. Taxes are provided as necessary with respect to earnings that are not permanently reinvested.

Derivative instruments

At times, we enter into derivative financial transactions to hedge existing or projected exposures to changing foreign currency exchange rates. We do not enter into derivative transactions for speculative or trading purposes. We recognize all derivatives on the balance sheet at fair value. Derivatives are adjusted to fair value and reflected through the results of operations. Gains or losses on foreign currency derivatives are included in “Other, net” in our consolidated statements of operations. Our derivatives are not designated as hedges for accounting purposes.

Foreign currency translation

Foreign entities whose functional currency is the United States dollar translate monetary assets and liabilities at year-end exchange rates, and nonmonetary items are translated at historical rates. Income and expense accounts are translated at the average rates in effect during the year, except for depreciation, cost of product sales and revenue, and expenses associated with nonmonetary balance sheet accounts, which are translated at historical rates. Gains or losses from changes in exchange rates are recognized in our consolidated statements of operations in “Other, net” in the year of occurrence.

Stock-based compensation

Stock-based compensation cost is measured at the date of grant, based on the calculated fair value of the award, and is recognized as expense over the employee’s service period, which is generally the vesting period of the equity grant. Additionally, compensation cost is recognized based on awards ultimately expected to vest, therefore, we have reduced the cost for estimated forfeitures based on historical forfeiture rates. Forfeitures are estimated at the time of grant and revised in subsequent periods to reflect actual forfeitures. See Note 10 for additional information related to stock-based compensation.

Note 2. Business Segment and Geographic Information

We operate under two divisions, which form the basis for the two operating segments we report: the Completion and Production segment and the Drilling and Evaluation segment.

Completion and Production delivers cementing, stimulation, intervention, pressure control, and completion services. The segment consists of production enhancement services, completion tools and services, cementing services, and Boots & Coots.

Production enhancement services include stimulation services and sand control services. Stimulation services optimize oil and natural gas reservoir production through a variety of pressure pumping services, nitrogen services, and chemical processes, commonly known as hydraulic fracturing and acidizing. Sand control services include fluid and chemical systems and pumping services for the prevention of formation sand production.

Completion tools and services include subsurface safety valves and flow control equipment, surface safety systems, packers and specialty completion equipment, intelligent completion systems, expandable liner hanger systems, sand control systems, well servicing tools, and reservoir performance services. Reservoir performance services include testing tools, real-time reservoir analysis, and data acquisition services.

Cementing services involve bonding the well and well casing while isolating fluid zones and maximizing wellbore stability. Our cementing service line also provides casing equipment.
Boots & Coots includes well intervention services, pressure control, equipment rental tools and services, and pipeline and process services.
Drilling and Evaluation provides field and reservoir modeling, drilling, evaluation, and precise wellbore placement solutions that enable customers to model, measure, and optimize their well construction activities. The segment consists of fluid services, drilling services, drill bits, wireline and perforating services, testing and subsea services, software and asset solutions, and integrated project management and consulting services.
Fluid services provides drilling fluid systems, performance additives, completion fluids, solids control, specialized testing equipment, and waste management services for oil and natural gas drilling, completion, and workover operations.
Drilling services provides drilling systems and services. These services include directional and horizontal drilling, measurement-while-drilling, logging-while-drilling, surface data logging, multilateral systems, underbalanced applications, and rig site information systems. Our drilling systems offer directional control for precise wellbore placement while providing important measurements about the characteristics of the drill string and geological formations while drilling wells. Real-time operating capabilities enable the monitoring of well progress and aid decision-making processes.
Drill bits provides roller cone rock bits, fixed cutter bits, hole enlargement and related downhole tools and services used in drilling oil and natural gas wells. In addition, coring equipment and services are provided to acquire cores of the formation drilled for evaluation.
Wireline and perforating services include open-hole wireline services that provide information on formation evaluation, including resistivity, porosity, density, rock mechanics, and fluid sampling. Also offered are cased-hole and slickline services, which provide cement bond evaluation, reservoir monitoring, pipe evaluation, pipe recovery, mechanical services, well intervention, perforating, and borehole seismic services. Perforating services include tubing-conveyed perforating services and products. Borehole seismic services include fracture analysis and mapping.
Testing and subsea services provide acquisition and analysis of dynamic reservoir information and reservoir optimization solutions to the oil and natural gas industry utilizing downhole test tools, data acquisition services using telemetry and electronic memory recording, fluid sampling, surface well testing, subsea safety systems, and reservoir engineering services.
Software and asset solutions is a supplier of integrated exploration, drilling, and production software information systems, as well as consulting and data management services for the upstream oil and natural gas industry.
The Drilling and Evaluation segment also provides oilfield project management and integrated solutions to independent, integrated, and national oil companies. These offerings make use of all of our oilfield services, products, technologies, and project management capabilities to assist our customers in optimizing the value of their oil and natural gas assets.
Corporate and other includes expenses related to support functions and corporate executives. Also included are certain gains and losses that are not attributable to a particular business segment. “Corporate and other” represents assets not included in a business segment and is primarily composed of cash and equivalents, deferred tax assets, and marketable securities.
Intersegment revenue and revenue between geographic areas are immaterial. Our equity in earnings and losses of unconsolidated affiliates that are accounted for under the equity method is included in revenue and operating income of the applicable segment.

The following tables present information on our business segments.

Operations by business segment

Millions of dollars	Year Ended December 31 2010	2009	2008
Revenue:			
Completion and Production	$ 9,997	$ 7,419	$ 9,610
Drilling and Evaluation	7,976	7,256	8,669
Total revenue	$ 17,973	$ 14,675	$ 18,279
Operating income:			
Completion and Production	$ 2,032	$ 1,016	$ 2,304
Drilling and Evaluation	1,213	1,183	1,970
Total operations	3,245	2,199	4,274
Corporate and other	(236)	(205)	(264)
Total operating income	$ 3,009	$ 1,994	$ 4,010
Interest expense, net of interest income	$ (297)	$ (285)	$ (128)
Other, net	(57)	(27)	(33)
Income from continuing operations before income taxes	$ 2,655	$ 1,682	$ 3,849
Capital expenditures:			
Completion and Production	$ 1,010	$ 900	$ 787
Drilling and Evaluation	1,058	959	1,031
Corporate and other	1	5	6
Total	$ 2,069	$ 1,864	$ 1,824
Depreciation, depletion, and amortization:			
Completion and Production	$ 537	$ 437	$ 358
Drilling and Evaluation	578	490	376
Corporate and other	4	4	4
Total	$ 1,119	$ 931	$ 738

Millions of dollars	December 31 2010	2009	2008
Total assets:			
Completion and Production	$ 7,815	$ 5,920	$ 5,936
Drilling and Evaluation	7,088	6,204	6,205
Shared assets	942	914	648
Corporate and other	2,452	3,500	1,596
Total	$ 18,297	$ 16,538	$ 14,385

Not all assets are associated with specific segments. Those assets specific to segments include receivables, inventories, certain identified property, plant, and equipment (including field service equipment), equity in and advances to related companies, and goodwill. The remaining assets, such as cash, are considered to be shared among the segments.

Revenue by country is determined based on the location of services provided and products sold.

Operations by geographic area

	Year Ended December 31		
Millions of dollars	2010	2009	2008
Revenue:			
United States	$ 8,209	$ 5,248	$ 7,775
Other countries	9,764	9,427	10,504
Total	$ 17,973	$ 14,675	$ 18,279

	December 31		
Millions of dollars	2010	2009	2008
Long-lived assets:			
United States	$ 5,389	$ 4,274	$ 3,571
Other countries	3,821	3,401	3,027
Total	$ 9,210	$ 7,675	$ 6,598

Note 3. Receivables

Our trade receivables are generally not collateralized. At December 31, 2010, 36% of our gross trade receivables were from customers in the United States. At December 31, 2009, 26% of our gross trade receivables were from customers in the United States. No other country or single customer accounted for more than 10% of our gross trade receivables at these dates.

The following table presents a rollforward of our allowance for bad debts for 2008, 2009, and 2010.

Millions of dollars Allowance for bad debts	Balance at Beginning of Period	Charged to Costs and Expenses	Write-Offs	Balance at End of Period
Year ended December 31, 2008:	$ 49	$ 14	$ (3)	$ 60
Year ended December 31, 2009:	60	37	(7)	90
Year ended December 31, 2010:	90	5	(4)	91

Note 4. Inventories

Inventories are stated at the lower of cost or market. In the United States we manufacture certain finished products and parts inventories for drill bits, completion products, bulk materials, and other tools that are recorded using the last-in, first-out method, which totaled $108 million at December 31, 2010 and $68 million at December 31, 2009. If the average cost method had been used, total inventories would have been $34 million higher than reported at December 31, 2010 and $33 million higher than reported at December 31, 2009. The cost of the remaining inventory was recorded on the average cost method. Inventories consisted of the following:

	December 31	
Millions of dollars	2010	2009
Finished products and parts	$ 1,369	$ 1,090
Raw materials and supplies	496	480
Work in process	75	28
Total	$ 1,940	$ 1,598

Finished products and parts are reported net of obsolescence reserves of $88 million at December 31, 2010 and $94 million at December 31, 2009.

Note 5. Property, Plant, and Equipment

Property, plant, and equipment were composed of the following:

	December 31	
Millions of dollars	2010	2009
Land	$ 105	$86
Buildings and property improvements	1,438	1,306
Machinery, equipment, and other	11,363	9,597
Total	12,906	10,989
Less accumulated depreciation	6,064	5,230
Net property, plant, and equipment	$ 6,842	$ 5,759

Classes of assets, excluding oil and natural gas investments, are depreciated over the following useful lives:

	Buildings and Property Improvements	
	2010	2009
1 – 10 years	13%	13%
11 – 20 years	46%	47%
21 – 30 years	13%	11%
31 – 40 years	28%	29%

	Machinery, Equipment, and Other	
	2010	2009
1 – 5 years	19%	19%
6 – 10 years	74%	75%
11 – 20 years	7%	6%

Note 6. Debt

Long-term debt consisted of the following:

	December 31	
Millions of dollars	2010	2009
6.15% senior notes due September 2019	$ 997	$ 997
7.45% senior notes due September 2039	995	995
6.7% senior notes due September 2038	800	800
5.9% senior notes due September 2018	400	400
7.6% senior debentures due August 2096	293	293
8.75% senior debentures due February 2021	184	184
5.5% senior notes due October 2010	–	750
Other	155	155
Total long-term debt	3,824	4,574
Less current maturities of long-term debt	–	750
Noncurrent portion of long-term debt (due 2017 and thereafter)	$ 3,824	$ 3,824

Senior debt

All of our senior notes and debentures rank equally with our existing and future senior unsecured indebtedness, have semiannual interest payments, and no sinking fund requirements. We may redeem all of our senior notes from time to time or all of the notes of each series at any time at the redemption prices, plus accrued and unpaid interest. Our 7.6% and 8.75% senior debentures may not be redeemed prior to maturity.

Revolving credit facilities

We have an unsecured, $1.2 billion credit facility expiring 2012 whose purpose is to provide commercial paper support, general working capital, and credit for other corporate purposes. There were no cash drawings under the revolving credit facilities as of December 31, 2010 or 2009.

Note 7. KBR Separation

During 2007, we completed the separation of KBR, Inc. (KBR) from us by exchanging KBR common stock owned by us for our common stock. In addition, we recorded a liability reflecting the estimated fair value of the indemnities and guarantees provided to KBR as described below. Since the separation, we have recorded adjustments to reflect changes to our estimation of our remaining obligation. All such adjustments are recorded in “Income (loss) from discontinued operations, net.”

We entered into various agreements relating to the separation of KBR, including, among others, a master separation agreement and a tax sharing agreement. The master separation agreement provides for, among other things, KBR's responsibility for liabilities related to its business and our responsibility for liabilities unrelated to KBR's business. We provide indemnification in favor of KBR under the master separation agreement for certain contingent liabilities, including our indemnification of KBR and any of its greater than 50%-owned subsidiaries as of November 20, 2006, the date of the master separation agreement, for:

- fines or other monetary penalties or direct monetary damages, including disgorgement, as a result of a claim made or assessed by a governmental authority in the United States, the United Kingdom, France, Nigeria, Switzerland, and/or Algeria, or a settlement thereof, related to alleged or actual violations occurring prior to November 20, 2006 of the United States Foreign Corrupt Practices Act (FCPA) or particular, analogous applicable foreign statutes, laws, rules, and regulations in connection with investigations pending as of that date, including with respect to the construction and subsequent expansion by a consortium of engineering firms comprised of Technip SA of France, Snamprogetti Netherlands B.V., JGC Corporation of Japan, and Kellogg Brown & Root LLC (TSKJ) of a natural gas liquefaction complex and related facilities at Bonny Island in Rivers State, Nigeria; and
- all out-of-pocket cash costs and expenses, or cash settlements or cash arbitration awards in lieu thereof, KBR may incur after the effective date of the master separation agreement as a result of the replacement of the subsea flowline bolts installed in connection with the Barracuda-Caratinga project.

Additionally, we provide performance guarantees, surety bond guarantees, and letter of credit guarantees that are currently in place in favor of KBR's customers or lenders under project contracts, letters of credit, and other KBR credit instruments. These guarantees will continue until they expire at the earlier of: (1) the termination of the underlying project contract or KBR obligations thereunder; or (2) the expiration of the relevant credit support instrument in accordance with its terms or release of such instrument by the customer. KBR has agreed to indemnify us, other than for the FCPA and Barracuda-Caratinga bolts matter, if we are required to perform under any of the guarantees related to KBR's letters of credit, surety bonds, or performance guarantees described above.

In February 2009, the United States Department of Justice (DOJ) and Securities and Exchange Commission (SEC) FCPA investigations were resolved. The total of fines and disgorgement was $579 million, of which KBR consented to pay $20 million. The entire amount has been paid. In December 2010, we resolved an investigation by the Federal Government of Nigeria (FGN) relating to criminal charges filed in connection with the Nigeria LNG project against various companies and individuals including TSKJ Nigeria Limited. In December 2010, pursuant to an agreement we paid $33 million to the FGN and an additional $2 million for FGN's attorneys' fees and other expenses. As of December 31, 2010, we have paid the full amounts due. In February 2011, an investigation by the Serious Fraud Office (SFO) in the United Kingdom was resolved. A tax benefit of $62 million related to the SEC settlement was recorded in discontinued operations during the third quarter of 2010. Amounts accrued relating to our remaining KBR indemnities and guarantees are primarily included in "Other liabilities" on the consolidated balance sheets and totaled $63 million at December 31, 2010. See Note 8 for further discussion of the TSKJ and Barracuda-Caratinga matters.

The tax sharing agreement provides for allocations of United States and certain other jurisdiction tax liabilities between us and KBR.

Note 8. Commitments and Contingencies

The Gulf of Mexico/Macondo well incident

Overview. The semisubmersible drilling rig, Deepwater Horizon, sank on April 22, 2010 after an explosion and fire onboard the rig that began on April 20, 2010. The Deepwater Horizon was owned by Transocean Ltd. and had been drilling the Macondo exploration well in Mississippi Canyon Block 252 in the Gulf of Mexico for the lease operator, BP Exploration & Production, Inc. (BP Exploration), an indirect wholly owned subsidiary of BP p.l.c. We performed a variety of services for BP Exploration, including cementing, mud logging, directional drilling, measurement-while-drilling, and rig data acquisition services. Crude oil flowing from the well site spread across thousands of square miles of the Gulf of Mexico and reached the United States Gulf Coast. Numerous attempts at estimating the volume of oil spilled have been made by various groups, and on August 2, 2010 the federal government published an estimate that approximately 4.9 million barrels of oil were discharged from the well. Efforts to contain the flow of hydrocarbons from the well were led by the United States government and by BP p.l.c., BP Exploration, and their affiliates (collectively, BP). The flow of hydrocarbons from the well ceased on July 15, 2010, and the well was permanently capped on September 19, 2010. There were eleven fatalities and a number of injuries as a result of the Macondo well incident.

As of December 31, 2010, we had not accrued any amounts related to this matter because we do not believe that a loss is probable. We are currently unable to estimate the full impact the Macondo well incident will have on us. Further, an estimate of possible loss or range of loss related to this matter cannot be made. Considering the complexity of the Macondo well, however, and the number of investigations being conducted and lawsuits pending, as discussed below, new information or future developments may require us to adjust our liability assessment, and liabilities arising out of this matter could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

Investigations and Regulatory Action. The United States Department of Homeland Security and Department of the Interior are jointly investigating the cause of the Macondo well incident. The United States Coast Guard, a component of the United States Department of Homeland Security, and the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly known as the Minerals Management Service), a bureau of the United States Department of the Interior, share jurisdiction over the investigation into the Macondo well incident and have formed a joint investigation team that continues to review information and hold hearings regarding the incident (Marine Board Investigation). We are named as one of the 16 parties-in-interest in the Marine Board Investigation. In addition, other investigations are underway by the Chemical Safety Board, the National Academy of Sciences, and the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (National Commission) that the President of the United States has established to, among other things, examine the relevant facts and circumstances concerning the causes of the Macondo well incident and develop options for guarding against future oil spills associated with offshore drilling. We are assisting in efforts to identify the factors that led to the Macondo well incident and have participated and intend to continue participating in various hearings relating to the incident that are held by, among others, certain of the agencies referred to above and various committees and subcommittees of the House of Representatives and the Senate of the United States.

In May 2010, the United States Department of the Interior effectively suspended all offshore deepwater drilling projects in the United States Gulf of Mexico. The suspension was lifted in October 2010. Since that time, the Department of the Interior has issued guidance for drillers that intend to resume deepwater drilling activity. There has been no material increase, however, in the level of drilling activity in the Gulf of Mexico since the suspension was lifted, and we believe that the prospects for any significant increase will remain uncertain through the first half, and perhaps the full year, of 2011. For additional information, see Item 1(a), "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Environment and Results of Operations."

DOJ Investigations and Actions. On June 1, 2010, the United States Attorney General announced that the DOJ was launching civil and criminal investigations into the Macondo well incident to closely examine the actions of those involved, and that the DOJ was working with attorneys general of states affected by the Macondo well incident. The DOJ announced that it was reviewing, among other traditional criminal statutes, possible violations of and liabilities under The Clean Water Act (CWA), The Oil Pollution Act of 1990 (OPA), The Migratory Bird Treaty Act of 1918 (MBTA), and the Endangered Species Act of 1973 (ESA).

The CWA provides authority for civil and criminal penalties for discharges of oil into or upon navigable waters of the United States, adjoining shorelines, or in connection with the Outer Continental Shelf Lands Act in quantities that are deemed harmful. Criminal sanctions under the CWA can be assessed for negligent discharges (up to $50,000 per day of violation), for knowing discharges (up to $100,000 per day of violation), and for knowing endangerment (up to $2 million per violation), and federal agencies could be precluded from contracting with a company that is criminally sanctioned under the CWA. Civil proceedings under the CWA can be commenced against an "owner, operator or person in charge of any vessel or offshore facility that discharged oil or a hazardous substance." The civil penalties that can be imposed against responsible parties range from up to $1,100 per barrel of oil discharged in the case of those found strictly liable to $4,300 per barrel of oil discharged in the case of those found to have been grossly negligent.

The OPA establishes liability for discharges of oil from vessels, onshore facilities, and offshore facilities into or upon the navigable waters of the United States. Under the OPA, the "responsible party" for the discharging vessel or facility is liable for removal and response costs as well as for damages, including recovery costs to contain and remove discharged oil and compensation for injury to natural resources. The cap on liability under the OPA is the full cost of removal of the discharged oil plus up to $75 million for natural resources damages, except that the cap on natural resources damages does not apply in the event the damage was proximately caused by gross negligence or the violation of certain federal standards. The OPA defines the set of responsible parties differently depending on whether the source of the discharge is a vessel or an offshore facility. Liability for vessels is imposed on owners and operators; liability for offshore facilities is imposed on the holder of the permit or lessee of the area in which the facility is located.

The MBTA and the ESA provide penalties for injury and death to wildlife and bird species. The MBTA provides that violators are strictly liable and provides for fines of up to $15,000 per bird killed and imprisonment of up to six months. The ESA provides for civil penalties for knowing violations that can range up to $25,000 per violation and, in the case of criminal penalties, up to $50,000 per violation.

In addition, the Alternative Fines Act may be applied in lieu of the express amount of the criminal fines that may be imposed under the statutes described above in the amount of twice the gross economic loss suffered by third parties (or twice the gross economic gain realized by the defendant, if greater).

On December 15, 2010, the DOJ filed a civil action seeking damages and injunctive relief against BP, Anadarko, Transocean and others for violations of the CWA and the OPA. The DOJ's complaint seeks an action declaring that the defendants are strictly liable under the CWA as a result of harmful discharges of oil into the Gulf of Mexico and upon U.S. shorelines as a result of the Macondo well incident. The complaint also seeks an action declaring that the defendants are strictly liable under the OPA for the discharge of oil that has resulted in, among other things, injury to, loss of, loss of use of or destruction of natural resources and resource services in and around the Gulf of Mexico and the adjoining U.S. shorelines and resulting in removal costs and damages to the United States far exceeding $75 million. BP has been designated, and has accepted the designation, as a responsible party for the pollution under the CWA and the OPA. Others have also been named as responsible parties, and all responsible parties may be held jointly and severally liable for any damages under the OPA, although a responsible party may make a claim for contribution against any other "responsible party" it alleges contributed to the oil spill or any other person it alleges was the sole cause of the oil spill.

We were not named as a responsible party under the CWA or the OPA in the DOJ civil action, and we do not believe we are a "responsible party" under the CWA or the OPA. While we were not included in the DOJ's complaint, there can be no assurance that we will not be joined in the action or that the DOJ or other federal or state governmental authorities will not bring an action, whether civil or criminal, against us under other statutes or regulations. In connection with the DOJ's filing of the action, it announced that its criminal and civil investigations are continuing and that it will employ efforts to hold accountable those who are responsible for the incident. As of February 17, 2011, no criminal proceedings have been commenced against us.

In June 2010, we received a letter from the DOJ requesting thirty days advance notice of any event that may involve substantial transfers of cash or other corporate assets outside of the ordinary course of business. In our reply to the June 2010 DOJ letter, we conveyed our interest in briefing the DOJ on the services we provided on the Deepwater Horizon but indicated that we would not bind ourselves to the DOJ request. Subsequently, we have had and expect to continue to have discussions with the DOJ regarding the Macondo well incident and the request contained in the June 2010 DOJ letter.

Investigative Reports. On September 8, 2010, an incident investigation team assembled by BP issued the Deepwater Horizon Accident Investigation Report (BP Report). The BP Report outlines eight key findings of BP related to the possible causes of the Macondo well incident, including failures of cement barriers, failures of equipment provided by other service companies and the drilling contractor, and failures of judgment by BP and the drilling contractor. With respect to the BP Report's assessment that the cement barrier did not prevent hydrocarbons from entering the wellbore after cement placement, the BP Report concluded that, among other things, there were "weaknesses in cement design and testing." According to the BP Report, the BP incident investigation team did not review its analyses or conclusions with us or any other entity or governmental agency conducting a separate or independent investigation of the incident. In addition, the BP incident investigation team did not conduct any testing using our cementing products.

On January 11, 2011, the National Commission released "Deep Water -- The Gulf Oil Disaster and the Future of Offshore Drilling," its investigation report (Investigation Report) to the President of the United States regarding, among other things, the National Commission's conclusions of the causes of the Macondo well incident. According to the Investigation Report, the "immediate causes" of the incident were the result of a series of missteps, oversights, miscommunications and failures to appreciate risk by BP, Transocean, and us, although the National Commission acknowledged that there were still many things it did not know about the incident, such as the role of the blowout preventer. The National Commission also acknowledged that it may never know the extent to which each mistake or oversight caused the Macondo well incident, but concluded that the immediate cause was "a failure to contain hydrocarbon pressures in the well," and pointed to three things that could have contained those pressures: "the cement at the bottom of the well, the mud in the well and in the riser, and the blowout preventer." In addition, the Investigation Report stated that "primary cement failure was a direct cause of the blowout" and that cement testing performed by an independent laboratory "strongly suggests" that the foam cement slurry used on the Macondo well was unstable. The Investigation Report, however, acknowledges a fact widely accepted by the industry that cementing wells is a complex endeavor utilizing an inherently uncertain process in which failures are not uncommon and that, as a result, the industry utilizes the negative pressure test and cement bond log test, among others, to identify cementing failures that require remediation before further work on a well is performed.

The Investigation Report also sets forth the National Commission's findings on certain missteps, oversights and other factors that may have caused, or contributed to the cause of, the incident, including BP's decision to use a long string casing instead of a liner casing, BP's decision to use only six centralizers, BP's failure to run a cement bond log, BP's reliance on the primary cement job as a barrier to a possible blowout, BP's and Transocean's failure to properly conduct and interpret a negative-pressure test, BP's temporary abandonment procedures, and the failure of the drilling crew and our surface data logging specialist to recognize that an unplanned influx of oil, gas or fluid into the well (known as a "kick") was occurring. With respect to the National Commission's finding that our surface data logging specialist failed to recognize a kick, the Investigation Report acknowledged that there were simultaneous activities and other monitoring responsibilities that may have prevented the surface data logging specialist from recognizing a kick.

The Investigation Report also identified two general root causes of the Macondo well incident: systemic failures by industry management, which the National Commission labeled "the most significant failure at Macondo," and failures in governmental and regulatory oversight. The National Commission cited examples of failures by industry management such as BP's lack of controls to adequately identify or address risks arising from changes to well design and procedures, the failure of BP's and our processes for cement testing, communication failures among BP, Transocean, and us, including with respect to the difficulty of our cement job, Transocean's failure to adequately communicate lessons from a recent near-blowout, and the lack of processes to adequately assess the risk of decisions in relation to the time and cost those decisions would save. With respect to failures of governmental and regulatory oversight, the National Commission concluded that applicable drilling regulations were inadequate, in part because of a lack of resources and political support of the Minerals Management Service (MMS), and a lack of expertise and training of MMS personnel to enforce regulations that were in effect.

We expect National Commission staff to issue a separate, more detailed report regarding the causes of the Macondo well incident sometime in the first quarter 2011.

The Cementing Job and Reaction to Reports. We disagree with the BP Report and the National Commission regarding many of their findings and characterizations with respect to the cementing and surface data logging services on the Deepwater Horizon. We have provided information to the National Commission and its staff that we believe has been overlooked or selectively omitted from the Investigation Report. We intend to continue to vigorously defend ourselves in any investigation relating to our involvement with the Macondo well that we believe inaccurately evaluates or depicts our services on the Deepwater Horizon.

The cement slurry on the Deepwater Horizon was designed and prepared pursuant to well condition data provided by BP. Regardless of whether alleged weaknesses in cement design and testing are or are not ultimately established, and regardless of whether the cement slurry was utilized in similar applications or was prepared consistent with industry standards, we believe that had BP and others properly interpreted a negative-pressure test, this test would have revealed any problems with the cement. In addition, had BP designed the Macondo well to allow a full cement bond log test or if BP had conducted even a partial cement bond log test, the test likely would have revealed any problems with the cement. BP, however, elected not to conduct any cement bond log test, and with others misinterpreted the negative-pressure test, both of which could have resulted in remedial action, if appropriate, with respect to the cementing services.

At this time we cannot predict the impact of the Investigation Report or the conclusions of future reports of the National Commission, the Marine Board Investigation, the Chemical Safety Board, the National Academy of Sciences, Congressional committees, or any other governmental or private entity. In addition, although we have not been served by the DOJ or any state agency, we cannot predict whether their investigations or any other report or investigation will have an influence on or result in our being named as a party in any action alleging violation of a statute or regulation, whether federal or state and whether criminal or civil.

We intend to continue to cooperate fully with all governmental hearings, investigations, and requests for information relating to the Macondo well incident. We cannot predict the outcome of, or the costs to be incurred in connection with, any of these hearings or investigations, and therefore we cannot predict the potential impact they may have on us.

Litigation. Beginning on April 21, 2010, plaintiffs started filing lawsuits relating to the Macondo well incident. Generally, those lawsuits allege either (1) damages arising from the oil spill pollution and contamination (e.g., diminution of property value, lost tax revenue, lost business revenue, lost tourist dollars, inability to engage in recreational or commercial activities) or (2) wrongful death or personal injuries. To date, we have been named along with other unaffiliated defendants in more than 330 complaints, most of which are alleged class actions, involving pollution damage claims and at least 28 personal injury lawsuits involving six decedents and 54 allegedly injured persons who were on the drilling rig at the time of the incident. Another six lawsuits naming us and others relate to alleged personal injuries sustained by those responding to the explosion and oil spill. Plaintiffs originally filed the lawsuits described above in federal and state courts throughout the United States, including Alabama, Delaware, Florida, Georgia, Kentucky, Louisiana, Mississippi, South Carolina, Tennessee, Texas, and Virginia. Except for approximately 25 lawsuits not yet consolidated, one lawsuit that is proceeding in Louisiana state court, and one lawsuit that is proceeding in Texas state court, the Judicial Panel on Multi-District Litigation ordered all of the lawsuits consolidated in a multi-district litigation (MDL) proceeding before Judge Carl Barbier in the U.S. Eastern District of Louisiana. The pollution complaints generally allege, among other things, negligence and gross negligence, property damages, taking of protected species, and potential economic losses as a result of environmental pollution and generally seek awards of unspecified economic, compensatory, and punitive damages, as well as injunctive relief. Plaintiffs in these pollution cases have brought suit under various legal provisions, including the OPA, the CWA, the MBTA, the ESA, the Outer Continental Shelf Lands Act, the Longshoremen and Harbor Workers Compensation Act, general maritime law, STATE COMMON LAW, and various state environmental and products liability statutes.

Furthermore, the pollution complaints include suits brought by governmental entities, including the State of Alabama, Plaquemines Parish, and three Mexican states. The wrongful death and other personal injury complaints generally allege negligence and gross negligence and seek awards of compensatory damages, including unspecified economic damages and punitive damages. We have retained counsel and are investigating and evaluating the claims, the theories of recovery, damages asserted, and our respective defenses to all of these claims.

According to case management and pre-trial orders, with respect to the MDL, the court may try one or more OPA "test cases" as early as third quarter 2011. These test cases, the number and specificity of which have not been determined, will consist of claims brought against BP as a responsible party under the OPA. The same judge is also presiding over a separate proceeding filed by Transocean under the Limitation of Liability Act (Limitation Action). In the Limitation Action, Transocean seeks to limit its liability for claims arising out of the Macondo well incident to the value of the rig and its freight. Although the Limitation Action is not consolidated in the MDL, to this point the judge is effectively treating the two proceedings as associated cases. Although we are not yet formally a party to the Limitation Action, we expect that Transocean will tender all defendants into the Limitation Action in February 2011. As a result of that anticipated tender, all defendants will be treated as direct defendants to the plaintiffs' claims as if the plaintiffs had sued each defendant directly.

In the Limitation Action, the judge intends to determine the allocation of liability among all defendants in the hundreds of lawsuits associated with the Macondo well incident that are pending in his court. More specifically, the court intends to try one or more "personal injury/wrongful death test cases" and one or more economic damage claim "test cases" in the first quarter 2012 in an attempt to determine liability, limitation, exoneration and fault allocation with regard to all of the defendants. We do not believe, however, that a single apportionment of liability in the Limitation Action is properly applied to the hundreds of lawsuits pending in the MDL Proceeding. Damages for the personal injury/wrongful death and economic damage claim "test cases" tried in the first quarter 2012, including punitive damages, are expected to be tried in a second phase of the Limitation Action. Under ordinary MDL procedures, such trials would, unless waived by the respective parties, be tried in the courts from which they were transferred into the MDL. It remains unclear, however, what impact the overlay of the Limitation Action will have on where these matters are tried.

Additional civil lawsuits may be filed against us. Document discovery and depositions among the parties to the MDL have begun. The deadline for defendants to file cross claims and third-party claims arising out of the Macondo well incident against other defendants is March 18, 2011.

We intend to vigorously defend any litigation, fines, and/or penalties relating to the Macondo well incident.

Shareholder derivative case. In February 2011, a shareholder derivative lawsuit was filed in Harris County, Texas naming us as a nominal defendant and certain of our directors and officers as defendants. This case alleges that these defendants, among other things, breached fiduciary duties of good faith and loyalty by failing to properly exercise oversight responsibilities and establish adequate internal controls, including controls and procedures related to cement testing and the communication of test results, as they relate to the Deepwater Horizon incident. Due to the preliminary status of the lawsuit and uncertainties related to litigation, we are unable to evaluate the likelihood of either a favorable or unfavorable outcome.

Indemnification and Insurance. Our contract with BP Exploration relating to the Macondo well provides for our indemnification for potential claims and expenses relating to the Macondo well incident, including those resulting from pollution or contamination (other than claims by our employees, loss or damage to our property, and any pollution emanating directly from our equipment). Also, under our contract with BP Exploration, we have, among other things, generally agreed to indemnify BP Exploration and other contractors performing work on the well for claims for personal injury of our employees and subcontractors, as well as for damage to our property. In turn, we believe that BP Exploration is obligated to obtain agreement by other contractors performing work on the well to indemnify us for claims for personal injury of their employees or subcontractors as well as for damages to their property.

In addition to the contractual indemnity, we have a general liability insurance program of $600 million. Our insurance is designed to cover claims by businesses and individuals made against us in the event of property damage, injury or death and, among other things, claims relating to environmental damage. To the extent we incur any losses beyond those covered by indemnification, there can be no assurance that our insurance policies will cover all potential claims and expenses relating to the Macondo well incident. Insurance coverage can be the subject of uncertainties and, particularly in the event of large claims, potential disputes with insurance carriers, as well as other potential parties claiming insured status under our insurance policies.

Given the potential amounts involved, BP Exploration and other indemnifying parties may seek to avoid their indemnification obligations. In particular, while we do not believe there is any justification to do so, BP Exploration, in response to our request for indemnification, on June 25, 2010 generally reserved all of its rights and stated that it is premature to conclude that it is obligated to indemnify us. In doing so, BP Exploration has asserted that the facts were not sufficiently developed to determine who is responsible, and cited a variety of possible legal theories based upon the contract and facts still to be developed. As indicated above, all cross claims among defendants must be filed by March 18, 2011. We expect that all defendants will make claims against each other and deny that they owe any indemnification or other obligations to any other defendant.

Indemnification for criminal fines or penalties, if any, may not be available if a court were to find such indemnification unenforceable as against public policy. We do not expect, however, public policy to limit substantially the enforceability of our contractual right to indemnification with respect to liabilities other than criminal fines and penalties, if any. We may not be insured with respect to civil or criminal fines or penalties, if any, pursuant to the terms of our insurance policies.

We believe the law likely to be held applicable to matters relating to the Macondo well incident does not allow for enforcement of indemnification of persons who are found to be grossly negligent, although we do not believe the performance of our services on the Deepwater Horizon constituted gross negligence. In addition, certain state laws, if deemed to apply, may not allow for enforcement of indemnification of persons who are found to be negligent with respect to personal injury claims. In addition, financial analysts and the press have speculated about the financial capacity of BP, and whether it might seek to avoid indemnification obligations in bankruptcy proceedings. We consider the likelihood of a BP bankruptcy to be remote.

TSKJ matters

Background. As a result of an ongoing FCPA investigation at the time of the KBR separation, we provided indemnification in favor of KBR under the master separation agreement for certain contingent liabilities, including our indemnification of KBR and any of its greater than 50%-owned subsidiaries as of November 20, 2006, the date of the master separation agreement, for fines or other monetary penalties or direct monetary damages, including disgorgement, as a result of a claim made or assessed by a governmental authority in the United States, the United Kingdom, France, Nigeria, Switzerland, and/or Algeria, or a settlement thereof, related to alleged or actual violations occurring prior to November 20, 2006 of the FCPA or particular, analogous applicable foreign statutes, laws, rules, and regulations in connection with investigations pending as of that date, including with respect to the construction and subsequent expansion by TSKJ of a multibillion dollar natural gas liquefaction complex and related facilities at Bonny Island in Rivers State, Nigeria. As a condition of our indemnity, we have control over the investigation, defense, and/or settlement of these matters. We have the right to terminate the indemnity in the event KBR elects to take control over the investigation, defense, and/or settlement or refuses to agree to a settlement negotiated and presented by us.

TSKJ is a private limited liability company registered in Madeira, Portugal whose members are Technip SA of France, Snamprogetti Netherlands B.V. (a subsidiary of Saipem SpA of Italy), JGC Corporation of Japan, and Kellogg Brown & Root LLC (a subsidiary of KBR), each of which had an approximate 25% beneficial interest in the venture. Part of KBR's ownership in TSKJ was held through M.W. Kellogg Limited (MWKL), a United Kingdom joint venture and subcontractor on the Bonny Island project, in which KBR beneficially owned a 55% interest at the time of the execution of the master separation agreement. TSKJ and other similarly owned entities entered into various contracts to build and expand the liquefied natural gas project for Nigeria LNG Limited, which is owned by the Nigerian National Petroleum Corporation, Shell Gas B.V., Cleag Limited (an affiliate of Total), and Agip International B.V. (an affiliate of ENI SpA of Italy).

DOJ, SEC, United Kingdom, and Nigerian Government investigations resolved. In 2009, the FCPA investigations by the DOJ and the SEC were resolved with respect to KBR and us. The DOJ and SEC investigations resulted from allegations of improper payments to government officials in Nigeria in connection with the construction and subsequent expansion by TSKJ of the Bonny Island project.

The DOJ investigation was resolved with respect to us with a non-prosecution agreement in which the DOJ agreed not to bring FCPA or bid coordination-related charges against us with respect to the matters under investigation, and in which we agreed to continue to cooperate with the DOJ's ongoing investigation and to refrain from and self-report certain FCPA violations. The DOJ agreement did not provide a monitor for us.

KBR has agreed that our indemnification obligations with respect to the DOJ and SEC FCPA investigations have been fully satisfied.

As part of the resolution of the SEC investigation, we retained an independent consultant to conduct a 60-day review and evaluation of our internal controls and record-keeping policies as they relate to the FCPA. The review and evaluation were completed during the second quarter of 2009, and we have implemented the consultant's recommendations. As a result of the substantial enhancement of our anti-bribery and foreign agent internal controls and record-keeping procedures prior to the review of the independent consultant, we do not expect the implementation of the consultant's recommendations to materially impact our long-term strategy to grow our international operations. In 2010, the independent consultant performed a 30-day, follow-up review, confirming that we have implemented the recommendations and continued the application of our current policies and procedures and to recommend any additional improvements.

In December 2010, we reached a settlement agreement to resolve charges filed by the FGN in late 2010. Pursuant to the agreement, all lawsuits and charges against KBR and our corporate entities and associated persons have been withdrawn, and the FGN agreed not to bring any further criminal charges or civil claims against those entities or persons, and we agreed to pay $33 million to the FGN and to pay an additional $2 million for FGN's attorneys' fees and other expenses. Among other provisions, we agreed to provide reasonable assistance in the FGN's effort to recover amounts frozen in a Swiss bank account of a former TSKJ agent and affirmed a continuing commitment with regard to corporate governance.

In February 2011, an investigation in the United Kingdom by the SFO focused on the actions of MWKL was resolved between the SFO and MWKL in full and final settlement of the case. The agreement was in the form of a civil settlement in which the SFO recognized that MWKL took no part in the criminal activity which generated the funds. Our indemnity for penalties under the master separation agreement with respect to MWKL was limited to 55% of such penalties, which was KBR's beneficial ownership interest in MWKL at the time of the execution of the master separation agreement.

The DOJ, SEC, United Kingdom, and FGN settlements and other future investigations and settlements, if any, could result in third-party claims against us, which may include claims for special, indirect, derivative or consequential damages, damage to our business or reputation, loss of, or adverse effect on, cash flow, assets, goodwill, results of operations, business prospects, profits or business value or claims by directors, officers, employees, affiliates, advisors, attorneys, agents, debt holders, or other interest holders or constituents of us or our current or former subsidiaries.

Our indemnity of KBR and its majority-owned subsidiaries continues with respect to other investigations within the scope of our indemnity. Our indemnification obligation to KBR does not include losses resulting from third-party claims against KBR, including claims for special, indirect, derivative or consequential damages, nor does our indemnification apply to damage to KBR's business or reputation, loss of, or adverse effect on, cash flow, assets, goodwill, results of operations, business prospects, profits or business value or claims by directors, officers, employees, affiliates, advisors, attorneys, agents, debt holders, or other interest holders or constituents of KBR or KBR's current or former subsidiaries.

At this time, no other claims by governmental authorities in foreign jurisdictions have been asserted against the indemnified parties. Therefore, we are unable to estimate the maximum potential amount of future payments that could be required to be made under our indemnity to KBR and its majority-owned subsidiaries related to these matters. Our estimation of the indemnity obligation regarding TSKJ matters is recorded as a liability in our consolidated financial statements as of December 31, 2010 and December 31, 2009. See Note 7 for additional information regarding the KBR indemnification.

Barracuda-Caratinga arbitration

We also provided indemnification in favor of KBR under the master separation agreement for all out-of-pocket cash costs and expenses (except for legal fees and other expenses of the arbitration so long as KBR controls and directs it), or cash settlements or cash arbitration awards, KBR may incur after November 20, 2006 as a result of the replacement of certain subsea flowline bolts installed in connection with the Barracuda-Caratinga project. Under the master separation agreement, KBR currently controls the defense, counterclaim, and settlement of the subsea flowline bolts matter. As a condition of our indemnity, for any settlement to be binding upon us, KBR must secure our prior written consent to such settlement's terms. We have the right to terminate the indemnity in the event KBR enters into any settlement without our prior written consent.

At Petrobras' direction, KBR replaced certain bolts located on the subsea flowlines that failed through mid-November 2005, and KBR has informed us that additional bolts have failed thereafter, which were replaced by Petrobras. These failed bolts were identified by Petrobras when it conducted inspections of the bolts. We understand KBR believes several possible solutions may exist, including replacement of the bolts. Initial estimates by KBR indicated that costs of these various solutions ranged up to $148 million. In March 2006, Petrobras commenced arbitration against KBR claiming $220 million plus interest for the cost of monitoring and replacing the defective bolts and all related costs and expenses of the arbitration, including the cost of attorneys' fees. The arbitration panel held an evidentiary hearing in March 2008 to determine which party is responsible for the designation of the material used for the bolts. On May 13, 2009, the arbitration panel held that KBR and not Petrobras selected the material to be used for the bolts. Accordingly, the arbitration panel held that there is no implied warranty by Petrobras to KBR as to the suitability of the bolt material and that the parties' rights are to be governed by the express terms of their contract. The parties presented evidence and witnesses to the panel in May 2010, and final arguments were presented in August 2010. We are awaiting a final decision from the arbitration panel. Our estimation of the indemnity obligation regarding the Barracuda-Caratinga arbitration is recorded as a liability in our consolidated financial statements as of December 31, 2010 and December 31, 2009. See Note 7 for additional information regarding the KBR indemnification.

Securities and related litigation

In June 2002, a class action lawsuit was filed against us in federal court alleging violations of the federal securities laws after the SEC initiated an investigation in connection with our change in accounting for revenue on long-term construction projects and related disclosures. In the weeks that followed, approximately twenty similar class actions were filed against us. Several of those lawsuits also named as defendants several of our present or former officers and directors. The class action cases were later consolidated, and the amended consolidated class action complaint, styled Richard Moore, et al. v. Halliburton Company, et al., was filed and served upon us in April 2003. As a result of a substitution of lead plaintiffs, the case is now styled Archdiocese of Milwaukee Supporting Fund (AMSF) v. Halliburton Company, et al. We settled with the SEC in the second quarter of 2004.

In June 2003, the lead plaintiffs filed a motion for leave to file a second amended consolidated complaint, which was granted by the court. In addition to restating the original accounting and disclosure claims, the second amended consolidated complaint included claims arising out of the 1998 acquisition of Dresser Industries, Inc. by Halliburton, including that we failed to timely disclose the resulting asbestos liability exposure.

In April 2005, the court appointed new co-lead counsel and named AMSF the new lead plaintiff, directing that it file a third consolidated amended complaint and that we file our motion to dismiss. The court held oral arguments on that motion in August 2005, at which time the court took the motion under advisement. In March 2006, the court entered an order in which it granted the motion to dismiss with respect to claims arising prior to June 1999 and granted the motion with respect to certain other claims while permitting AMSF to re-plead some of those claims to correct deficiencies in its earlier complaint. In April 2006, AMSF filed its fourth amended consolidated complaint. We filed a motion to dismiss those portions of the complaint that had been re-pled. A hearing was held on that motion in July 2006, and in March 2007 the court ordered dismissal of the claims against all individual defendants other than our Chief Executive Officer (CEO). The court ordered that the case proceed against our CEO and Halliburton.

In September 2007, AMSF filed a motion for class certification, and our response was filed in November 2007. The court held a hearing in March 2008, and issued an order November 3, 2008 denying AMSF's motion for class certification. AMSF then filed a motion with the Fifth Circuit Court of Appeals requesting permission to appeal the district court's order denying class certification. The Fifth Circuit granted AMSF's motion. Both parties filed briefs, and the Fifth Circuit heard oral argument in December of 2009. The Fifth Circuit affirmed the district court's order denying class certification. On May 13, 2010, AMSF filed a writ of certiorari in the United States Supreme Court. In early January 2011, the Supreme Court granted AMSF's writ of certiorari and accepted the appeal. The parties will now submit legal briefs to the Court and the Court will hear oral arguments in April 2011. The appeal is limited to review of the legal ruling of the Fifth Circuit affirming the lower court's order denying class certification and will not include review of the facts of the underlying lawsuit. As of December 31, 2010, we had not accrued any amounts related to this matter because we do not believe that a loss is probable. Further, an estimate of possible loss or range of loss related to this matter cannot be made.

Shareholder derivative cases

In May 2009, two shareholder derivative lawsuits involving us and KBR were filed in Harris County, Texas naming as defendants various current and retired Halliburton directors and officers and current KBR directors. These cases allege that the individual Halliburton defendants violated their fiduciary duties of good faith and loyalty to the detriment of Halliburton and its shareholders by failing to properly exercise oversight responsibilities and establish adequate internal controls. The District Court consolidated the two cases and the plaintiffs filed a consolidated petition against current and former Halliburton directors and officers only containing various allegations of wrongdoing including violations of the FCPA, claimed KBR offenses while acting as a government contractor in Iraq, claimed KBR offenses and fraud under United States government contracts, Halliburton activity in Iran, and illegal kickbacks. Our Board of Directors has designated a special committee of independent directors to oversee the investigation of the allegations made in the lawsuits and make recommendations to the Board on actions that should be taken. As of December 31, 2010, we had not accrued any amounts related to this matter because we do not believe that a loss is probable. Further, an estimate of possible loss or range of loss related to this matter cannot be made.

Environmental

We are subject to numerous environmental, legal, and regulatory requirements related to our operations worldwide. In the United States, these laws and regulations include, among others:

- the Comprehensive Environmental Response, Compensation, and Liability Act;
- the Resource Conservation and Recovery Act;
- the Clean Air Act;
- the Federal Water Pollution Control Act; and
- the Toxic Substances Control Act.

In addition to the federal laws and regulations, states and other countries where we do business often have numerous environmental, legal, and regulatory requirements by which we must abide. We evaluate and address the environmental impact of our operations by assessing and remediating contaminated properties in order to avoid future liabilities and comply with environmental, legal, and regulatory requirements. On occasion, we are involved in specific environmental litigation and claims, including the remediation of properties we own or have operated, as well as efforts to meet or correct compliance-related matters. Our Health, Safety and Environment group has several programs in place to maintain environmental leadership and to prevent the occurrence of environmental contamination.

We do not expect costs related to these remediation requirements to have a material adverse effect on our consolidated financial position or our results of operations. Our accrued liabilities for environmental matters were $47 million as of December 31, 2010 and $53 million as of December 31, 2009. Our total liability related to environmental matters covers numerous properties.

We have subsidiaries that have been named as potentially responsible parties along with other third parties for 12 federal and state superfund sites for which we have established reserves. As of December 31, 2010, those 12 sites accounted for approximately $10 million of our total $47 million reserve. For any particular federal or state superfund site, since our estimated liability is typically within a range and our accrued liability may be the amount on the low end of that range, our actual liability could eventually be well in excess of the amount accrued. Despite attempts to resolve these superfund matters, the relevant regulatory agency may at any time bring suit against us for amounts in excess of the amount accrued. With respect to some superfund sites, we have been named a potentially responsible party by a regulatory agency; however, in each of those cases, we do not believe we have any material liability. We also could be subject to third-party claims with respect to environmental matters for which we have been named as a potentially responsible party.

Guarantee arrangements

In the normal course of business, we have agreements with financial institutions under which approximately $1.5 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2010, including $210 million of surety bonds related to Venezuela. In addition, $52 million of the total $1.5 billion relates to KBR letters of credit, bank guarantees, or surety bonds that are being guaranteed by us in favor of KBR’s customers and lenders. KBR has agreed to compensate us for these guarantees and indemnify us if we are required to perform under any of these guarantees. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization.

Leases

We are obligated under operating leases, principally for the use of land, offices, equipment, manufacturing and field facilities, and warehouses. Total rentals, net of sublease rentals, were $591 million in 2010, $528 million in 2009, and $561 million in 2008.

Future total rentals on noncancellable operating leases are as follows: $161 million in 2011; $122 million in 2012; $87 million in 2013; $50 million in 2014; $41 million in 2015; and $149 million thereafter.

Note 9. Income Taxes
The components of the (provision)/benefit for income taxes on continuing operations were:

	Year Ended December 31		
Millions of dollars	2010	2009	2008
Current income taxes:			
Federal	$ (400)	$ 30	$ (561)
Foreign	(287)	(250)	(346)
State	(42)	(24)	(50)
Total current	(729)	(244)	(957)
Deferred income taxes:			
Federal	(124)	(237)	(303)
Foreign	3	(31)	64
State	(3)	(6)	(15)
Total deferred	(124)	(274)	(254)
Provision for income taxes	$ (853)	$ (518)	$ (1,211)

The United States and foreign components of income from continuing operations before income taxes were as follows:

	Year Ended December 31		
Millions of dollars	2010	2009	2008
United States	$ 1,918	$ 589	$ 2,674
Foreign	737	1,093	1,175
Total	$ 2,655	$ 1,682	$ 3,849

Reconciliations between the actual provision for income taxes on continuing operations and that computed by applying the United States statutory rate to income from continuing operations before income taxes were as follows:

	Year Ended December 31		
	2010	2009	2008
United States statutory rate	35.0 %	35.0 %	35.0 %
Domestic manufacturing deduction	(1.8)	–	(1.1)
Impact of foreign income taxed at different rates	(1.3)	(3.3)	(1.1)
Adjustments of prior year taxes	(1.2)	(2.1)	(1.9)
Other impact of foreign operations	(1.3)	(0.4)	(1.1)
Impact of devaluation of Venezuelan Bolívar Fuerte	0.8	–	–
Other items, net	1.9	1.6	1.7
Total effective tax rate on continuing operations	32.1 %	30.8 %	31.5 %

The primary components of our deferred tax assets and liabilities were as follows:

	December 31	
Millions of dollars	2010	2009
Gross deferred tax assets:		
Employee compensation and benefits	$ 313	$ 266
Accrued liabilities	77	75
Net operating loss carryforwards	52	64
Capitalized research and experimentation	44	56
Insurance accruals	47	48
Software revenue recognition	50	35
Inventory	28	29
Other	106	95
Total gross deferred tax assets	717	668
Gross deferred tax liabilities:		
Depreciation and amortization	631	447
Joint ventures, partnerships, and unconsolidated affiliates	48	33
Other	57	55
Total gross deferred tax liabilities	736	535
Valuation allowances – net operating loss carryforwards	22	15
Net deferred income tax asset (liability)	$ (41)	$ 118

At December 31, 2010, we had a total of $179 million of foreign net operating loss carryforwards, of which $38 million will expire from 2011 through 2021. The balance will not expire due to indefinite expiration dates.

The following table presents a rollforward of our unrecognized tax benefits and associated interest and penalties.

Millions of dollars	Unrecognized Tax Benefits	Interest and Penalties
Balance at January 1, 2008	$ 388	$ 37
Change in prior year tax positions	(98)	5
Change in current year tax positions	25	2
Cash settlements with taxing authorities	(5)	–
Lapse of statute of limitations	(10)	(1)
Balance at December 31, 2008	$ 300	$ 43
Change in prior year tax positions	(42)	(6)
Change in current year tax positions	23	2
Cash settlements with taxing authorities	(7)	(1)
Lapse of statute of limitations	(11)	(9)
Balance at December 31, 2009	$ 263(a)	$ 29
Change in prior year tax positions	(74)	7
Change in current year tax positions	19	2
Cash settlements with taxing authorities	(28)	(5)
Lapse of statute of limitations	(3)	(1)
Balance at December 31, 2010	$ 177(a)(b)	$ 32

(a) Includes $62 million and $149 million as of December 31, 2010 and 2009 in amounts to be settled in accordance with our Tax Sharing Agreement with KBR and foreign unrecognized tax benefits that would give rise to a United State tax credit. The remaining balance of $115 and $ 114 million as of December 31, 2010 and 2009, if resolved in our favor, would positively impact the effective tax rate and, therefore, be recognized as additional tax benefits in our statement of operations.

(b) Includes $32 million that could be resolved within the next 12 months.

We file income tax returns in the United States federal jurisdiction and in various states and foreign jurisdictions. In most cases, we are no longer subject to state, local, or non-United States income tax examination by tax authorities for years before 2000. Tax filings of our subsidiaries, unconsolidated affiliates, and related entities are routinely examined in the normal course of business by tax authorities. Currently, our United States federal tax filings are under review for tax years 2006 through 2007.

Note 10. Shareholders' Equity and Stock Incentive Plans

The following tables summarize our common stock and other shareholders' equity activity:

	Company Shareholders' Equity						
Millions of dollars	Common Shares	Paid-in Capital in Excess of Par Value	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest in Consolidated Subsidiaries	Total
Balance at December 31, 2007	$ 2,657	$ 1,804	$ (5,630)	$ 8,146	$ (104)	$ 93	$ 6,966
Cash dividends paid	–	–	–	(319)	–	–	(319)
Stock plans	9	41	173	–	–	–	223
Common shares purchased	–	–	(507)	–	–	–	(507)
Tax benefit from exercise of options and restricted stock	–	45	–	–	–	–	45
Distributions to noncontrolling interest holders	–	–	–	–	–	(2)	(2)
Other transactions with shareholders	–	–	–	–	–	(63)	(63)
Total dividends and other transactions with shareholders	9	86	(334)	(319)	–	(65)	(623)
Adoption of new accounting standards	–	(693)	–	(10)	–	–	(703)
Portion of the convertible debt premium settled in stock, at cost	–	(713)	713	–	–	–	–
Comprehensive income (loss):							
Net income	–	–	–	2,224	–	(9)	2,215
Other comprehensive income (loss):							
Cumulative translation adjustment	–	–	–	–	1	–	1
Defined benefit and other postretirement plans adjustments:							
Actuarial net loss	–	–	–	–	(170)	–	(170)
Other	–	–	–	–	18	–	18
Tax effect on defined benefit and							

postretirement plans	–	–	–	–	46	–	46
Defined benefit and other postretirement plans, net	–	–	–	–	(106)	–	(106)
Net unrealized losses on investments, net of tax benefit of $4	–	–	–	–	(6)	–	(6)
Total comprehensive income	–	–	–	2,224	(111)	(9)	2,104
Balance at December 31, 2008	$ 2,666	$ 484	$ (5,251)	$ 10,041	$ (215)	$ 19	$ 7,744

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	Company Shareholders' Equity						
Millions of dollars	Common Shares	Paid-in Capital in Excess of Par Value	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest in Consolidated Subsidiaries	Total
Balance at December 31, 2008	$ 2,666	$ 484	$ (5,251)	$ 10,041	$ (215)	$ 19	$ 7,744
Cash dividends paid	–	–	–	(324)	–	–	(324)
Stock plans	3	(51)	266	–	–	–	218
Common shares purchased	–	–	(17)	–	–	–	(17)
Tax loss from exercise of options and restricted stock	–	(22)	–	–	–	–	(22)
Other	–	–	–	1	–	–	1
Total dividends and other transactions with shareholders	3	(73)	249	(323)	–	–	(144)
Comprehensive income (loss):							
Net income	–	–	–	1,145	–	10	1,155
Other comprehensive income (loss):							
Cumulative translation adjustment	–	–	–	–	(5)	–	(5)
Defined benefit and other postretirement plans, net	–	–	–	–	2	–	2
Net unrealized gains on investments, net of tax provision of $3	–	–	–	–	5	–	5
Total comprehensive income	–	–	–	1,145	2	10	1,157
Balance at December 31, 2009	$ 2,669	$ 411	$ (5,002)	$ 10,863	$ (213)	$ 29	$ 8,757
Cash dividends paid	–	–	–	(327)	–	–	(327)
Stock plans	5	(37)	252	–	–	–	220
Common shares purchased	–	–	(141)	–	–	–	(141)
Tax loss from exercise of options and restricted stock	–	(18)	–	–	–	–	(18)
Other	–	–	–	–	–	(21)	(21)
Total dividends and other transactions with shareholders	5	(55)	111	(327)	–	(21)	(287)

Treasury shares issued for acquisition	–	(17)	120	–	–	–	103
Comprehensive income (loss):							
Net income	–	–	–	1,835	–	7	1,842
Other comprehensive income (loss):							
Cumulative translation adjustment	–	–	–	–	(1)	–	(1)
Defined benefit and other postretirement plans adjustments, net	–	–	–	–	(26)	(1)	(27)
Total comprehensive income	–	–	–	1,835	(27)	6	1,814
Balance at December 31, 2010	$ 2,674	$ 339	$ (4,771)	$ 12,371	$ (240)	$ 14	$ 10,387

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Accumulated other comprehensive loss	December 31		
Millions of dollars	2010	2009	2008
Cumulative translation adjustment	$ (66)	$ (65)	$ (60)
Defined benefit and other postretirement liability adjustments (a)	(175)	(149)	(151)
Unrealized gains (losses) on investments	1	1	(4)
Total accumulated other comprehensive loss	$ (240)	$ (213)	$ (215)

(a) Included net actuarial losses of $38 million for our United States pension plans and $170 million for our international pension plans at December 31, 2010, $36 million for our United States pension plans and $149 million for our international pension plans at December 31, 2009, and $37 million for our United States pension plans and $161 million for our international pension plans at December 31, 2008.

Shares of common stock	December 31		
Millions of shares	2010	2009	2008
Issued	1,069	1,067	1,067
In treasury	(159)	(165)	(172)
Total shares of common stock outstanding	910	902	895

Our stock repurchase program has an authorization of $5.0 billion, of which $1.7 billion remained available at December 31, 2010. The program does not require a specific number of shares to be purchased and the program may be effected through solicited or unsolicited transactions in the market or in privately negotiated transactions. The program may be terminated or suspended at any time. From the inception of this program in February 2006 through December 31, 2010, we have repurchased approximately 96 million shares of our common stock for approximately $3.3 billion at an average price per share of $34.23. These numbers include the repurchase of approximately 3.5 million shares of our common stock for approximately $114 million at an average price per share of $32.44 during 2010.

Preferred Stock

Our preferred stock consists of five million total authorized shares at December 31, 2010, of which none are issued.

Stock Incentive Plans

The following table summarizes stock-based compensation costs for the years ended December 31, 2010, 2009 and 2008.

	Year Ended December 31		
Millions of dollars	2010	2009	2008
Stock-based compensation cost	$ 158	$ 143	$ 103
Tax benefit	$ (50)	$ (46)	$ (33)
Stock-based compensation cost, net of tax	$ 108	$ 97	$ 70

Our Stock and Incentive Plan, as amended (Stock Plan), provides for the grant of any or all of the following types of stock-based awards:

- stock options, including incentive stock options and nonqualified stock options;
- restricted stock awards;
- restricted stock unit awards;
- stock appreciation rights; and
- stock value equivalent awards.

There are currently no stock appreciation rights or stock value equivalent awards outstanding.

Under the terms of the Stock Plan, approximately 133 million shares of common stock have been reserved for issuance to employees and non-employee directors. At December 31, 2010, approximately 24 million shares were available for future grants under the Stock Plan. The stock to be offered pursuant to the grant of an award under the Stock Plan may be authorized but unissued common shares or treasury shares.

In addition to the provisions of the Stock Plan, we also have stock-based compensation provisions under our Restricted Stock Plan for Non-Employee Directors and our Employee Stock Purchase Plan (ESPP).

Each of the active stock-based compensation arrangements is discussed below.

Stock options

The majority of our options are generally issued during the second quarter of the year. All stock options under the Stock Plan are granted at the fair market value of our common stock at the grant date. Employee stock options vest ratably over a three- or four-year period and generally expire 10 years from the grant date. Stock options granted to non-employee directors vest after six months. Compensation expense for stock options is generally recognized on a straight line basis over the entire vesting period. No further stock option grants are being made under the stock plans of acquired companies.

The following table represents our stock options activity during 2010.

Stock Options	Number of Shares (in millions)	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (years)	Aggregate Intrinsic Value (in millions)
Outstanding at January 1, 2010	15.2	$ 25.17		
Granted	3.1	28.88		
Exercised	(2.2)	17.93		
Forfeited/expired	(0.3)	29.89		
Outstanding at December 31, 2010	15.8	$ 26.79	6.6	$ 235
Exercisable at December 31, 2010	9.5	$ 26.30	5.1	$ 147

The total intrinsic value of options exercised was $38 million in 2010, $10 million in 2009, and $106 million in 2008. As of December 31, 2010, there was $37 million of unrecognized compensation cost, net of estimated forfeitures, related to nonvested stock options, which is expected to be recognized over a weighted average period of approximately 2 years.

Cash received from option exercises was $102 million during 2010, $74 million during 2009, and $120 million during 2008. The tax benefit realized from the exercise of stock options was $5 million in 2010, $3 million in 2009, and $33 million in 2008.

The fair value of options at the date of grant was estimated using the Black-Scholes option pricing model. The expected volatility of options granted was a blended rate based upon implied volatility calculated on actively traded options on our common stock and upon the historical volatility of our common stock. The expected term of options granted was based upon historical observation of actual time elapsed between date of grant and exercise of options for all employees. The assumptions and resulting fair values of options granted were as follows:

	Year Ended December 31		
	2010	2009	2008
Expected term (in years)	5.27	5.18	5.20
Expected volatility	39.77%	53.06%	32.30%
Expected dividend yield	0.99 – 1.71%	1.23 – 2.55%	0.71 – 2.38%
Risk-free interest rate	1.20 – 2.78%	1.38 – 2.47%	1.57 – 3.32%
Weighted average grant-date fair value per share	$ 9.94	$ 9.36	$ 12.28

Restricted stock

Restricted shares issued under the Stock Plan are restricted as to sale or disposition. These restrictions lapse periodically over an extended period of time not exceeding 10 years. Restrictions may also lapse for early retirement and other conditions in accordance with our established policies. Upon termination of employment, shares on which restrictions have not lapsed must be returned to us, resulting in restricted stock forfeitures. The fair market value of the stock on the date of grant is amortized and charged to income on a straight-line basis over the requisite service period for the entire award.

Our Restricted Stock Plan for Non-Employee Directors (Directors Plan) allows for each non-employee director to receive an annual award of 800 restricted shares of common stock as a part of their compensation. These awards have a minimum restriction period of six months, and the restrictions lapse upon the earlier of mandatory director retirement at age 72 or early retirement from the Board after four years of service. The fair market value of the stock on the date of grant is amortized over the lesser of the time from the grant date to age 72 or the time from the grant date to completion of four years of service on the Board. We reserved 200,000 shares of common stock for issuance to non-employee directors, which may be authorized but unissued common shares or treasury shares. At December 31, 2010, 138,400 shares had been issued to non-employee directors under this plan. There were 8,000 shares, 8,000 shares, and 7,200 shares of restricted stock awarded under the Directors Plan in 2010, 2009, and 2008. In addition, during 2010, our non-employee directors were awarded 35,710 shares of restricted stock under the Stock Plan, which are included in the table below.

The following table represents our Stock Plan and Directors Plan restricted stock awards and restricted stock units granted, vested, and forfeited during 2010.

Restricted Stock	Number of Shares (in millions)	Weighted Average Grant-Date Fair Value per Share
Nonvested shares at January 1, 2010	12.3	$ 27.63
Granted	4.8	29.39
Vested	(3.3)	28.15
Forfeited	(0.5)	28.33
Nonvested shares at December 31, 2010	13.3	$ 28.10

The weighted average grant-date fair value of shares granted during 2009 was $22.90 and during 2008 was $36.78. The total fair value of shares vested during 2010 was $100 million, during 2009 was $59 million, and during 2008 was $81 million. As of December 31, 2010, there was $270 million of unrecognized compensation cost, net of estimated forfeitures, related to nonvested restricted stock, which is expected to be recognized over a weighted average period of 3 years.

Employee Stock Purchase Plan

Under the ESPP, eligible employees may have up to 10% of their earnings withheld, subject to some limitations, to be used to purchase shares of our common stock. Unless the Board of Directors shall determine otherwise, each six-month offering period commences on January 1 and July 1 of each year. The price at which common stock may be purchased under the ESPP is equal to 85% of the lower of the fair market value of the common stock on the commencement date or last trading day of each offering period. Under this plan, 44 million shares of common stock have been reserved for issuance. They may be authorized but unissued shares or treasury shares. As of December 31, 2010, 22.7 million shares have been sold through the ESPP.

The fair value of ESPP shares was estimated using the Black-Scholes option pricing model. The expected volatility was a one-year historical volatility of our common stock. The assumptions and resulting fair values were as follows:

	Offering period July 1 through December 31		
	2010	2009	2008
Expected term (in years)	0.5	0.5	0.5
Expected volatility	43.30%	80.41%	28.88%
Expected dividend yield	1.44%	1.74%	0.67%
Risk-free interest rate	0.21%	0.33%	2.17%
Weighted average grant-date fair value per share	$ 6.72	$ 7.66	$ 12.58

	Offering period January 1 through June 30		
	2010	2009	2008
Expected term (in years)	0.5	0.5	0.5
Expected volatility	47.70%	70.91%	24.69%
Expected dividend yield	1.15%	1.85%	0.93%
Risk-free interest rate	0.19%	0.27%	3.40%
Weighted average grant-date fair value per share	$ 8.81	$ 6.69	$ 8.64

Note 11. Income per Share

Basic income per share is based on the weighted average number of common shares outstanding during the period. Diluted income per share includes additional common shares that would have been outstanding if potential common shares with a dilutive effect had been issued.

A reconciliation of the number of shares used for the basic and diluted income per share calculations is as follows:

Millions of shares	2010	2009	2008
Basic weighted average common shares outstanding	908	900	883
Dilutive effect of:			
Convertible senior notes premium (a)	–	–	22
Stock options			4

	3	2	
Diluted weighted average common shares outstanding	911	902	909

(a) 3.125% convertible senior notes due 2023, which were settled during the third quarter of 2008.

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Excluded from the computation of diluted income per share are options to purchase five million shares of common stock that were outstanding in 2010, seven million shares of common stock that were outstanding in 2009, and four million shares of common stock that were outstanding in 2008. These options were outstanding during these years but were excluded because they were antidilutive, as the option exercise price was greater than the average market price of the common shares.

Note 12. Financial Instruments and Risk Management

Foreign exchange risk

Techniques in managing foreign exchange risk include, but are not limited to, foreign currency borrowing and investing and the use of currency derivative instruments. We selectively manage significant exposures to potential foreign exchange losses considering current market conditions, future operating activities, and the associated cost in relation to the perceived risk of loss. The purpose of our foreign currency risk management activities is to protect us from the risk that the eventual dollar cash flows resulting from the sale and purchase of services and products in foreign currencies will be adversely affected by changes in exchange rates.

We manage our currency exposure through the use of currency derivative instruments as it relates to the major currencies, which are generally the currencies of the countries in which we do the majority of our international business. These instruments are not treated as hedges for accounting purposes and generally have an expiration date of one year or less. Forward exchange contracts, which are commitments to buy or sell a specified amount of a foreign currency at a specified price and time, are generally used to manage identifiable foreign currency commitments. Forward exchange contracts are generally used to manage exposures related to assets and liabilities denominated in a foreign currency. None of the forward contracts are exchange traded. While derivative instruments are subject to fluctuations in value, the fluctuations are generally offset by the value of the underlying exposures being managed. The use of some contracts may limit our ability to benefit from favorable fluctuations in foreign exchange rates.

Foreign currency contracts are not utilized to manage exposures in some currencies due primarily to the lack of available markets or cost considerations (non-traded currencies). We attempt to manage our working capital position to minimize foreign currency commitments in non-traded currencies and recognize that pricing for the services and products offered in these countries should cover the cost of exchange rate devaluations. We have historically incurred transaction losses in non-traded currencies.

Notional amounts and fair market values. The notional amounts of open foreign exchange forward contracts were $356 million at December 31, 2010 and $318 million at December 31, 2009. The notional amounts of our foreign exchange contracts do not generally represent amounts exchanged by the parties and, thus, are not a measure of our exposure or of the cash requirements related to these contracts. The amounts exchanged are calculated by reference to the notional amounts and by other terms of the derivatives, such as exchange rates. The estimated fair market value of our foreign exchange contracts was not material at either December 31, 2010 or December 31, 2009.

Credit risk

Financial instruments that potentially subject us to concentrations of credit risk are primarily cash equivalents, investments, and trade receivables. It is our practice to place our cash equivalents and investments in high quality securities with various investment institutions. We derive the majority of our revenue from sales and services to the energy industry. Within the energy industry, trade receivables are generated from a broad and diverse group of customers. There are concentrations of receivables in the United States. We maintain an allowance for losses based upon the expected collectability of all trade accounts receivable. In addition, see Note 3 for discussion of receivables.

There are no significant concentrations of credit risk with any individual counterparty related to our derivative contracts. We select counterparties based on their profitability, balance sheet, and a capacity for timely payment of financial commitments, which is unlikely to be adversely affected by foreseeable events.

Interest rate risk

Our outstanding debt instruments have fixed interest rates.

At December 31, 2010, we held $653 million in marketable securities with maturities that extend through July 2011. These securities are accounted for as available-for-sale and recorded at fair value in "Investments in marketable securities."

Fair market value of financial instruments. The carrying amount of cash and equivalents, receivables, and accounts payable, as reflected in the consolidated balance sheets, approximates fair market value due to the short maturities of these instruments. The following table presents the fair values of our other material financial assets and liabilities and the basis for determining their fair values:

Millions of dollars	Carrying Value	Fair Value	Quoted Prices in Active Markets for Identical Assets or Liabilities	Significant Observable Inputs for Similar Assets or Liabilities
December 31, 2010				
Marketable securities	$ 653	$ 653	$ 653	$ –
Long-term debt	3,824	4,604	4,182	422(a)
December 31, 2009				
Marketable securities	$ 1,312	$ 1,312	$ 1,312	$ –
Long-term debt	4,574	5,301	4,874	427(a)

(a) Calculated based on the fair value of other actively-traded, Halliburton debt.

Note 13. Retirement Plans

Our company and subsidiaries have various plans that cover a significant number of our employees. These plans include defined contribution plans, defined benefit plans, and other postretirement plans:

- our defined contribution plans provide retirement benefits in return for services rendered. These plans provide an individual account for each participant and have terms that specify how contributions to the participant's account are to be determined rather than the amount of pension benefits the participant is to receive. Contributions to these plans are based on pretax income and/or discretionary amounts determined on an annual basis. Our expense for the defined contribution plans for continuing operations totaled $196 million in 2010, $186 million in 2009, and $178 million in 2008;
- our defined benefit plans, which include both funded and unfunded pension plans, define an amount of pension benefit to be provided, usually as a function of age, years of service, and/or compensation; and
- our postretirement medical plans are offered to specific eligible employees. The accumulated benefit obligations at December 31, 2010 and 2009 and net periodic benefit cost for these plans during 2010, 2009, and 2008 were not material.

For the 2010 annual reporting period, we adopted an update to existing accounting standards related to disclosure requirements for fair value measurements. Among other things, this update provides an amendment requiring a greater level of disaggregation in reporting fair value measurements of assets and liabilities. The conforming amendment to the guidance on employers' disclosures about postretirement benefit plan assets further disaggregates from major categories of assets to classes of assets.

For the 2009 annual reporting period, we adopted an update to existing accounting standards that amends the requirements for employers' disclosures about plan assets for defined benefit pension and other postretirement plans. The objectives of this update are to provide users of financial statements with an understanding of how investment allocation decisions are made, the inputs and valuation techniques used to measure the fair value of plan assets, significant concentrations of risk within the company's plan assets, and, for fair value measurements determined using significant unobservable inputs, a reconciliation of changes between the beginning and ending balances.

Funded status

The following table presents a reconciliation of the beginning and ending balances of the projected benefit obligation and fair value of plan assets and the funded status of our pension plans.

	2010		2009	
Millions of dollars	United States	International	United States	International
Benefit obligation				
Projected benefit obligation at beginning of period	$ 110	$ 833	$ 108	$ 690
Service cost	–	20	–	21
Interest cost	6	49	5	44
Actuarial loss	9	64	11	81
Benefits paid	(6)	(23)	(6)	(27)
Settlements/curtailments	(4)	(10)	(8)	(35)
Currency fluctuations	–	(28)	–	57
Other	–	3	–	2
Projected benefit obligation at end of period	$ 115	$ 908	$ 110	$ 833
Accumulated benefit obligation at end of period	$ 115	$ 829	$ 110	$ 764

	2010		2009	
Millions of dollars	United States	International	United States	International
Plan assets				
Fair value of plan assets at beginning of period	$ 80	$ 642	$ 66	$ 430
Actual return on plan assets	8	72	14	107
Employer contributions	4	29	14	85
Benefits paid	(6)	(23)	(6)	(27)
Currency fluctuations	–	(25)	–	48
Other	(4)	(4)	(8)	(1)
Fair value of plan assets at end of period	$ 82	$ 691	$ 80	$ 642
Funded status at end of period	$ (33)	$ (217)	$ (30)	$ (191)

	2010		2009	
Millions of dollars	United States	International	United States	International
Amounts recognized on the Consolidated Balance Sheets				
Accrued employee compensation and benefits	$ –	$ (15)	$ –	$ (15)
Employee compensation and benefits	(33)	(202)	(30)	(177)
Pension plans in which projected benefit obligation exceeded plan assets at December 31				
Projected benefit obligation	$ 115	$ 902	$ 110	$ 821
Fair value of plan assets	82	685	80	629
Pension plans in which accumulated benefit obligation exceeded plan assets at December 31				
Accumulated benefit obligation	$ 115	$ 764	$ 110	$ 690
Fair value of plan assets	82	614	80	562

Fair value measurements of plan assets

The following table sets forth by level within the fair value hierarchy the fair value of assets held by our United States pension plans.

Millions of dollars	Quoted Prices in Active Markets for Identical Assets	Significant Observable Inputs for Similar Assets	Total
United States equity securities	$ 34	$ –	$ 34
Non-United States equity securities	18	–	18
Other assets	1	29	30
Fair value of plan assets at December 31, 2010	$ 53	$ 29	$ 82
United States equity securities	$ 31	$ –	$ 31
Non-United States equity securities	18	–	18
Other assets	1	30	31
Fair value of plan assets at December 31, 2009	$ 50	$ 30	$ 80

The following table sets forth by level within the fair value hierarchy the fair value of assets held by our international pension plans.

Millions of dollars	Quoted Prices in Active Markets for Identical Assets	Significant Observable Inputs for Similar Assets	Significant Unobservable Inputs	Total
Common/collective trust funds (a)				
Equity funds	$ –	$ 155	$ –	$ 155
Bond funds	–	97	–	97
Balanced funds	–	14	–	14
Non-United States equity securities	133	–	–	133
Corporate bonds	–	84	–	84
United States equity securities	41	–	–	41
Other assets	82	6	79	167
Fair value of plan assets at December 31, 2010	$ 256	$ 356	$ 79	$ 691
Common/collective trust funds (b)	$ –	$ 202	$ –	$ 202
Non-United States equity securities	126	–	–	126
Corporate bonds	–	87	–	87
Government bonds	–	78	–	78
United States equity securities	41	–	–	41
Other assets	35	2	71	108
Fair value of plan assets at December 31, 2009	$ 202	$ 369	$ 71	$ 642

(a) Strategies are generally to invest in equity or bond securities, or a combination thereof, that match or outperform certain predefined indices.

(b) Included 84% of investments in non-United States equity securities, 14% of investments in United States equity securities, and 2% of investments in fixed income securities.

Equity securities are traded in active markets and valued based on their quoted fair value by independent pricing vendors. Government bonds and corporate bonds are valued using quotes from independent pricing vendors based on recent trading activity and other relevant information, including market interest rate curves, referenced credit spreads, and estimated prepayment rates. Common/collective trust funds are valued at the net asset value of units held by the plans at year-end.

Our investment strategy varies by country depending on the circumstances of the underlying plan. Typically, less mature plan benefit obligations are funded by using more equity securities, as they are expected to achieve long-term growth while exceeding inflation. More mature plan benefit obligations are funded using more fixed income securities, as they are expected to produce current income with limited volatility. The fixed income allocation is generally invested with a similar maturity profile to that of the benefit obligations to ensure that changes in interest rates are adequately reflected in the assets of the plan. Risk management practices include diversification by issuer, industry, and geography, as well as the use of multiple asset classes and investment managers within each asset class.

For our United States pension plans, the target asset allocation is 50% to 75% equity securities and 30% to 45% fixed income securities. For our United Kingdom pension plan, which constituted 74% of our international pension plans' projected benefit obligations at December 31, 2010, the target asset allocation is 65% equity securities and 35% fixed income securities.

Net periodic benefit cost

The components of net periodic benefit cost for our pension plans for the years ended December 31 were as follows:

	2010		2009		2008	
Millions of dollars	United States	International	United States	International	United States	International
Service cost	$ –	$ 20	$ –	$ 21	$ –	$ 29
Interest cost	6	49	5	44	6	50
Expected return on plan assets	(7)	(43)	(7)	(38)	(7)	(44)
Other	5	2	6	5	3	11
Net periodic benefit cost	$ 4	$ 28	$ 4	$ 32	$ 2	$ 46

Actuarial assumptions

Certain weighted-average actuarial assumptions used to determine benefit obligations at December 31 were as follows:

	2010	2009
Discount rate:		
United States pension plans	4.9%	5.5%
International pension plans	5.7%	6.1%
Rate of compensation increase:		
International pension plans	5.2%	5.2%

Certain weighted-average actuarial assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	2010	2009	2008
Discount rate:			
United States pension plans	5.4%	5.7%	5.5%
International pension plans	7.9%	7.4%	7.1%
Expected long-term return on plan assets:			
United States pension plans	8.0%	8.0%	8.0%
International pension plans	5.6%	5.6%	5.9%
Rate of compensation increase:			
International pension plans	6.4%	5.7%	5.9%

Assumed long-term rates of return on plan assets, discount rates for estimating benefit obligations, and rates of compensation increases vary by plan according to local economic conditions. Discount rates were determined based on the prevailing market rates of a portfolio of high-quality debt instruments with maturities matching the expected timing of the payment of the benefit obligations. Expected long-term rates of return on plan assets were determined based upon an evaluation of our plan assets and historical trends and experience, taking into account current and expected market conditions.

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Expected cash flows

Contributions. Funding requirements for each plan are determined based on the local laws of the country where such plan resides. In certain countries the funding requirements are mandatory, while in other countries they are discretionary. We currently expect to contribute $33 million to our international pension plans and $8 million to our United States pension plans in 2011.

Benefit payments. Expected benefit payments over the next 10 years are approximately $8 million annually for our United States pension plans and approximately $25 million annually for our international pension plans.

Note 14. Accounting Standards Recently Adopted

On January 1, 2010, we adopted the provisions of a new accounting standard which provides amendments to previous guidance on the consolidation of variable interest entities. This standard clarifies the characteristics that identify a variable interest entity (VIE) and changes how a reporting entity identifies a primary beneficiary that would consolidate the VIE from a quantitative risk and rewards calculation to a qualitative approach based on which variable interest holder has controlling financial interest and the ability to direct the most significant activities that impact the VIE's economic performance. This standard requires the primary beneficiary assessment to be performed on a continuous basis. It also requires additional disclosures about an entity's involvement with a VIE, restrictions on the VIE's assets and liabilities that are included in the reporting entity's consolidated balance sheet, significant risk exposures due to the entity's involvement with the VIE, and how its involvement with a VIE impacts the reporting entity's consolidated financial statements. The standard is effective for fiscal years beginning after November 15, 2009. The adoption of this standard did not have a material impact on our consolidated financial statements.

HALLIBURTON COMPANY
Selected Financial Data (1)
(Unaudited)

Millions of dollars and shares except per share and employee data	Year Ended December 31				
	2010	2009	2008	2007	2006
Total revenue	$ 17,973	$ 14,675	$ 18,279	$ 15,264	$ 12,955
Total operating income	$ 3,009	$ 1,994	$ 4,010	$ 3,498	$ 3,245
Nonoperating expense, net	(354)	(312)	(161)	(51)	(59)
Income from continuing operations before income taxes	2,655	1,682	3,849	3,447	3,186
Provision for income taxes	(853)	(518)	(1,211)	(907)	(1,003)
Income from continuing operations	$ 1,802	$ 1,164	$ 2,638	$ 2,540	$ 2,183
Income (loss) from discontinued operations	$ 40	$ (9)	$ (423)	$ 996	$ 185
Net income	$ 1,842	$ 1,155	$ 2,215	$ 3,536	$ 2,368
Noncontrolling interest in net income of subsidiaries	(7)	(10)	9	(50)	(33)
Net income attributable to company	$ 1,835	$ 1,145	$ 2,224	$ 3,486	$ 2,335
Amounts attributable to company shareholders:					
Continuing operations	$ 1,795	$ 1,154	$ 2,647	$ 2,511	$ 2,164
Discontinued operations	40	(9)	(423)	975	171
Net income	1,835	1,145	2,224	3,486	2,335
Basic income per share attributable to shareholders:					
Continuing operations	$ 1.98	$ 1.28	$ 3.00	$ 2.73	$ 2.12
Net income	2.02	1.27	2.52	3.79	2.28
Diluted income per share attributable to shareholders:					
Continuing operations	1.97	1.28	2.91	2.63	2.04
Net income	2.01	1.27	2.45	3.65	2.20
Cash dividends per share	0.36	0.36	0.36	0.35	0.30
Return on average shareholders' equity	19.17 %	13.88 %	30.24 %	48.31 %	33.61 %
Financial position:					
Net working capital	$ 6,129	$ 5,749	$ 4,630	$ 5,162	$ 6,456
Total assets	18,297	16,538	14,385	13,135	16,860
Property, plant, and equipment, net	6,842	5,759	4,782	3,630	2,557
Long-term debt (including current maturities)	3,824	4,574	2,612	2,779	2,789
Total shareholders' equity	10,387	8,757	7,744	6,966	7,465
Total capitalization	14,241	13,331	10,369	9,756	10,255
Basic weighted average common shares					

outstanding	908	900	883	919	1,022
Diluted weighted average common shares					
outstanding	911	902	909	955	1,059
Other financial data:					
Capital expenditures	$ 2,069	$ 1,864	$ 1,824	$ 1,583	$ 834
Long-term borrowings (repayments), net	(790)	1,944	(861)	(7)	(324)
Depreciation, depletion, and amortization expense	1,119	931	738	583	480
Payroll and employee benefits	5,370	4,783	5,264	4,585	3,853
Number of employees	58,000	51,000	57,000	51,000	45,000

(1) All periods presented reflect the reclassification of KBR, Inc. to discontinued operations in the first quarter of 2007.

HALLIBURTON COMPANY
Quarterly Data and Market Price Information (1)
(Unaudited)

	Quarter				
Millions of dollars except per share data	First	Second	Third	Fourth	Year
2010					
Revenue	$3,761	$4,387	$4,665	$5,160	$17,973
Operating income	449	762	818	980	3,009
Net income	207	483	545	607	1,842
Amounts attributable to company shareholders:					
Income from continuing operations	211	474	485	625	1,795
Income (loss) from discontinued operations	(5)	6	59	(20)	40
Net income attributable to company	206	480	544	605	1,835
Basic income per share attributable to company shareholders:					
Income from continuing operations	0.23	0.52	0.53	0.69	1.98
Income (loss) from discontinued operations	–	0.01	0.07	(0.02)	0.04
Net income	0.23	0.53	0.60	0.67	2.02
Diluted income per share attributable to company shareholders:					
Income from continuing operations	0.23	0.52	0.53	0.68	1.97
Income (loss) from discontinued operations	–	0.01	0.07	(0.02)	0.04
Net income	0.23	0.53	0.60	0.66	2.01
Cash dividends paid per share	0.09	0.09	0.09	0.09	0.36
Common stock prices (1)					
High	34.87	35.22	33.84	41.73	41.73
Low	27.71	21.10	24.27	28.86	21.10
2009					
Revenue	$3,907	$3,494	$3,588	$3,686	$14,675
Operating income	616	476	474	428	1,994
Net income	380	265	266	244	1,155
Amounts attributable to company shareholders:					
Income from continuing operations	379	263	265	247	1,154
Loss from discontinued operations	(1)	(1)	(3)	(4)	(9)
Net income attributable to company	378	262	262	243	1,145
Basic income per share attributable to company shareholders:					
Income from continuing operations	0.42	0.29	0.29	0.27	1.28
Loss from discontinued operations	–	–	–	–	(0.01)
Net income	0.42	0.29	0.29	0.27	1.27
Diluted income per share attributable to company shareholders:					
Income from continuing operations	0.42	0.29	0.29	0.27	1.28
Loss from discontinued operations	–	–	–	–	(0.01)
Net income	0.42	0.29	0.29	0.27	1.27
Cash dividends paid per share	0.09	0.09	0.09	0.09	0.36

Common stock prices (1)					
High	21.47	24.76	28.58	32.00	32.00
Low	14.68	14.82	18.11	25.50	14.68

(1) New York Stock Exchange – composite transactions high and low intraday price.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance.
The information required for the directors of the Registrant is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the captions “Election of Directors” and “Involvement in Certain Legal Proceedings.” The information required for the executive officers of the Registrant is included under Part I on pages 4 through 5 of this annual report. The information required for a delinquent form required under Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Section 16(a) Beneficial Ownership Reporting Compliance,” to the extent any disclosure is required. The information for our code of ethics is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Corporate Governance.” The information regarding our Audit Committee and the independence of its members, along with information about the audit committee financial expert(s) serving on the Audit Committee, is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the caption “The Board of Directors and Standing Committees of Directors.”

Item 11. Executive Compensation.
This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the captions “Compensation Discussion and Analysis,” “Compensation Committee Report,” “Summary Compensation Table,” “Grants of Plan-Based Awards in Fiscal 2010,” “Outstanding Equity Awards at Fiscal Year End 2010,” “2010 Option Exercises and Stock Vested,” “2010 Nonqualified Deferred Compensation,” “Pension Benefits Table,” “Employment Contracts and Change-in-Control Arrangements,” “Post-Termination Payments,” “Equity Compensation Plan Information,” and “Directors’ Compensation.”

Item 12(a). Security Ownership of Certain Beneficial Owners.
This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Stock Ownership of Certain Beneficial Owners and Management.”

Item 12(b). Security Ownership of Management.
This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Stock Ownership of Certain Beneficial Owners and Management.”

Item 12(c). Changes in Control.
Not applicable.

Item 12(d). Securities Authorized for Issuance Under Equity Compensation Plans.
This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Equity Compensation Plan Information.”

Item 13. Certain Relationships and Related Transactions, and Director Independence.
This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Corporate Governance” to the extent any disclosure is required and under the caption “The Board of Directors and Standing Committees of Directors.”

Item 14. Principal Accounting Fees and Services.
This information is incorporated by reference to the Halliburton Company Proxy Statement for our 2011 Annual Meeting of Stockholders (File No. 1-3492) under the caption “Fees Paid to KPMG LLP.”

PART IV

Item 15. Exhibits

1. Financial Statements:

The reports of the Independent Registered Public Accounting Firm and the financial statements of the Company as required by Part II, Item 8, are included on pages 60 and 61 and pages 62 through 103 of this annual report. See index on page (i).

2. Exhibits:

Exhibit Number	Exhibits
2.1	Agreement and Plan of Merger dated April 9, 2010, by and among Halliburton Company, Gradient, LLC, and Boots & Coots, Inc. (incorporated by reference to Exhibit 2.1 to Halliburton's Form 8-K filed April 12, 2010, File No. 1-3492).
3.1	Restated Certificate of Incorporation of Halliburton Company filed with the Secretary of State of Delaware on May 30, 2006 (incorporated by reference to Exhibit 3.1 to Halliburton's Form 8-K filed June 5, 2006, File No. 1-3492).
3.2	By-laws of Halliburton revised effective February 10, 2010 (incorporated by reference to Exhibit 3.1 to Halliburton's Form 8-K filed February 10, 2010, File No. 1-3492).
4.1	Form of debt security of 8.75% Debentures due February 12, 2021 (incorporated by reference to Exhibit 4(a) to the Form 8-K of Halliburton Company, now known as Halliburton Energy Services, Inc. (the Predecessor), dated as of February 20, 1991, File No. 1-3492).
4.2	Senior Indenture dated as of January 2, 1991 between the Predecessor and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee (incorporated by reference to Exhibit 4(b) to the Predecessor's Registration Statement on Form S-3 (Registration No. 33-38394) originally filed with the Securities and Exchange Commission on December 21, 1990), as supplemented and amended by the First Supplemental Indenture dated as of December 12, 1996 among the Predecessor, Halliburton and the Trustee (incorporated by reference to Exhibit 4.1 of Halliburton's Registration Statement on Form 8-B dated December 12, 1996, File No. 1-3492).
4.3	Resolutions of the Predecessor's Board of Directors adopted at a meeting held on February 11, 1991 and of the special pricing committee of the Board of Directors of the Predecessor adopted at a meeting held on February 11, 1991 and the special pricing committee's consent in lieu of meeting dated February 12, 1991 (incorporated by reference to Exhibit 4(c) to the Predecessor's Form 8-K dated as of February 20, 1991, File No. 1-3492).

4.4 Second Senior Indenture dated as of December 1, 1996 between the Predecessor and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee, as supplemented and amended by the First Supplemental Indenture dated as of December 5, 1996 between the Predecessor and the Trustee and the Second Supplemental Indenture dated as of December 12, 1996 among the Predecessor, Halliburton and the Trustee (incorporated by reference to Exhibit 4.2 of Halliburton's Registration Statement on Form 8-B dated December 12, 1996, File No. 1-3492).

4.5 Third Supplemental Indenture dated as of August 1, 1997 between Halliburton and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee, to the Second Senior Indenture dated as of December 1, 1996 (incorporated by reference to Exhibit 4.7 to Halliburton's Form 10-K for the year ended December 31, 1998, File No. 1-3492).

4.6 Fourth Supplemental Indenture dated as of September 29, 1998 between Halliburton and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee, to the Second Senior Indenture dated as of December 1, 1996 (incorporated by reference to Exhibit 4.8 to Halliburton's Form 10-K for the year ended December 31, 1998, File No. 1-3492).

4.7 Resolutions of Halliburton's Board of Directors adopted by unanimous consent dated December 5, 1996 (incorporated by reference to Exhibit 4(g) of Halliburton's Form 10-K for the year ended December 31, 1996, File No. 1-3492).

4.8 Form of debt security of 6.75% Notes due February 1, 2027 (incorporated by reference to Exhibit 4.1 to Halliburton's Form 8-K dated as of February 11, 1997, File No. 1-3492).

4.9 Resolutions of Halliburton's Board of Directors adopted at a special meeting held on September 28, 1998 (incorporated by reference to Exhibit 4.10 to Halliburton's Form 10-K for the year ended December 31, 1998, File No. 1-3492).

4.10 Copies of instruments that define the rights of holders of miscellaneous long-term notes of Halliburton and its subsidiaries have not been filed with the Commission. Halliburton agrees to furnish copies of these instruments upon request.

4.11 Form of debt security of 7.53% Notes due May 12, 2017 (incorporated by reference to Exhibit 4.4 to Halliburton's Form 10-Q for the quarter ended March 31, 1997, File No. 1-3492).

4.12 Form of Indenture dated as of April 18, 1996 between Dresser and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), as Trustee (incorporated by reference to Exhibit 4 to Dresser's Registration Statement on Form S-3/A filed on April 19, 1996, Registration No. 333-01303), as supplemented and amended by Form of First Supplemental Indenture dated as of August 6, 1996 between Dresser and The Bank of New York Trust Company, N.A. (as successor to Texas Commerce Bank National Association), Trustee, for 7.60% Debentures due 2096 (incorporated by reference to Exhibit 4.1 to Dresser's Form 8-K filed on August 9, 1996, File No. 1-4003).

4.13 Second Supplemental Indenture dated as of October 27, 2003 between DII Industries, LLC and The Bank of New York Trust Company, N.A. (as successor to JPMorgan Chase Bank), as Trustee, to the Indenture dated as of April 18, 1996 (incorporated by reference to Exhibit 4.15 to Halliburton's Form 10-K for the year ended December 31, 2003, File No. 1-3492).

4.14 Third Supplemental Indenture dated as of December 12, 2003 among DII Industries, LLC, Halliburton and The Bank of New York Trust Company, N.A. (as successor to JPMorgan Chase Bank), as Trustee, to the Indenture dated as of April 18, 1996, (incorporated by reference to Exhibit 4.16 to Halliburton's Form 10-K for the year ended December 31, 2003, File No. 1-3492).

4.15 Indenture dated as of October 17, 2003 between Halliburton and The Bank of New York Trust Company, N.A. (as successor to JPMorgan Chase Bank), as Trustee (incorporated by reference to Exhibit 4.1 to Halliburton's Form 10-Q for the quarter ended September 30, 2003, File No. 1-3492).

4.16 Second Supplemental Indenture dated as of December 15, 2003 between Halliburton and The Bank of New York Trust Company, N.A. (as successor to JPMorgan Chase Bank), as Trustee, to the Senior Indenture dated as of October 17, 2003 (incorporated by reference to Exhibit 4.27 to Halliburton's Form 10-K for the year ended December 31, 2003, File No. 1-3492).

4.17 Form of note of 7.6% debentures due 2096 (included as Exhibit A to Exhibit 4.16 above).

4.18 Fourth Supplemental Indenture, dated as of September 12, 2008, between Halliburton and The Bank of New York Mellon Trust Company, N.A., as successor trustee to JPMorgan Chase Bank, to the Senior Indenture dated as of October 17, 2003 (incorporated by reference to Exhibit 4.2 to Halliburton's Form 8-K filed September 12, 2008, File No. 1-3492).

4.19 Form of Global Note for Halliburton's 5.90% Senior Notes due 2018 (included as part of Exhibit 4.18).

4.20 Form of Global Note for Halliburton's 6.70% Senior Notes due 2038 (included as part of Exhibit 4.18).

4.21 Fifth Supplemental Indenture, dated as of March 13, 2009, between Halliburton and The Bank of New York Mellon Trust Company, N.A., as successor trustee to JPMorgan Chase Bank, to the Senior Indenture dated as of October 17, 2003 (incorporated by reference to Exhibit 4.2 to Halliburton's Form 8-K filed March 13, 2009, File No. 1-3492).

4.22 Form of Global Note for Halliburton's 6.15% Senior Notes due 2019 (included as part of Exhibit 4.21).

4.23 Form of Global Note for Halliburton's 7.45% Senior Notes due 2039 (included as part of Exhibit 4.21).

10.1 Halliburton Company Restricted Stock Plan for Non-Employee Directors (incorporated by reference to Appendix B of the Predecessor's proxy statement dated March 23, 1993, File No. 1-3492).

10.2 Dresser Industries, Inc. Deferred Compensation Plan, as amended and restated effective January 1, 2000 (incorporated by reference to Exhibit 10.16 to Halliburton's Form 10-K for the year ended December 31, 2000, File No. 1-3492).

10.3 ERISA Excess Benefit Plan for Dresser Industries, Inc., as amended and restated effective June 1, 1995 (incorporated by reference to Exhibit 10.7 to Dresser's Form 10-K for the year ended October 31, 1995, File No. 1-4003).

10.4 ERISA Compensation Limit Benefit Plan for Dresser Industries, Inc., as amended and restated effective June 1, 1995 (incorporated by reference to Exhibit 10.8 to Dresser's Form 10-K for the year ended October 31, 1995, File No. 1-4003).

10.5 Employment Agreement (David J. Lesar) (incorporated by reference to Exhibit 10(n) to the Predecessor's Form 10-K for the year ended December 31, 1995, File No. 1-3492).

10.6 Employment Agreement (Mark A. McCollum) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended September 30, 2003, File No. 1-3492).

10.7 Halliburton Company Performance Unit Program (incorporated by reference to Exhibit 10.2 to Halliburton's Form 10-Q for the quarter ended September 30, 2001, File No. 1-3492).

10.8 Employment Agreement (Albert O. Cornelison) (incorporated by reference to Exhibit 10.3 to Halliburton's Form 10-Q for the quarter ended June 30, 2002, File No. 1-3492).

10.9 Master Separation Agreement between Halliburton Company and KBR, Inc. dated as of November 20, 2006 (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed November 27, 2006, File No. 1-3492).

10.10 Tax Sharing Agreement, effective as of January 1, 2006, by and between Halliburton Company, KBR Holdings, LLC and KBR, Inc., as amended effective February 26, 2007 (incorporated by reference to Exhibit 10.2 to KBR's Annual Report on Form 10-K for the year ended December 31, 2006, File No. 1-33146).

10.11 Five Year Revolving Credit Agreement among Halliburton, as Borrower, the Banks party thereto, and Citicorp North America, Inc., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed July 13, 2007, File No. 1-3492).

10.12 Form of Indemnification Agreement for Officers (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed August 3, 2007, File No. 1-3492).

10.13 Form of Indemnification Agreement for Directors (incorporated by reference to Exhibit 10.2 to Halliburton's Form 8-K filed August 3, 2007, File No. 1-3492).

10.14 2008 Halliburton Elective Deferral Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.3 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).

10.15 Halliburton Company Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.4 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).

10.16 Halliburton Company Benefit Restoration Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.5 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).

10.17 Halliburton Company Pension Equalizer Plan, as amended and restated effective March 1, 2007 (incorporated by reference to Exhibit 10.8 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).

10.18 Halliburton Company Directors' Deferred Compensation Plan, as amended and restated effective January 1, 2007 (incorporated by reference to Exhibit 10.9 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).

10.19 Retirement Plan for the Directors of Halliburton Company, as amended and restated effective July 1, 2007 (incorporated by reference to Exhibit 10.10 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).

10.20 First Amendment to the Retirement Plan for the Directors of Halliburton Company, effective September 1, 2007 (incorporated by reference to Exhibit 10.11 to Halliburton's Form 10-Q for the quarter ended September 30, 2007, File No. 1-3492).

10.21 Underwriting Agreement, dated September 9, 2008, among Halliburton and Citigroup Global Markets Inc., Greenwich Capital Markets, Inc. and HSBC Securities (USA) Inc., as representatives of the several underwriters identified therein (incorporated by reference to Exhibit 1.1 to Halliburton's Form 8-K filed September 12, 2008, File No. 1-3492).

10.22 Six Month Revolving Credit Agreement among Halliburton, as Borrower, the Banks party thereto, and HSBC Bank (USA) N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed October 16, 2008, File No. 1-3492).

10.23 Employment Agreement (James S. Brown) (incorporated by reference to Exhibit 10.36 to Halliburton's Form 10-K for the year ended December 31, 2007, File No. 1-3492).

10.24 Executive Agreement (Lawrence J. Pope) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed December 12, 2008, File No. 1-3492).

10.25 Underwriting Agreement, dated March 10, 2009, among Halliburton and Citigroup Global Markets Inc., Deutsche Bank Securities Inc., HSBC Securities (USA) Inc. and Greenwich Capital Markets, Inc., as representatives of the several underwriters identified therein (incorporated by reference to Exhibit 1.1 to Halliburton's Form 8-K filed March 13, 2009, File No. 1-3492).

10.26 Halliburton Company Stock and Incentive Plan, as amended and restated effective February 11, 2009 (incorporated by reference to Appendix B of Halliburton's proxy statement filed April 6, 2009, File No. 1-3492).

10.27 Halliburton Company Employee Stock Purchase Plan, as amended and restated effective February 11, 2009 (incorporated by reference to Appendix C of Halliburton's proxy statement filed April 6, 2009, File No. 1-3492).

10.28 Form of Nonstatutory Stock Option Agreement (incorporated by reference to Exhibit 10.4 of Halliburton's Form 10-Q for the quarter ended September 30, 2009, File No. 1-3492).

10.29 Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.5 of Halliburton's Form 10-Q for the quarter ended September 30, 2009, File No. 1-3492).

10.30 Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.6 of Halliburton's Form 10-Q for the quarter ended September 30, 2009, File No. 1-3492).

10.31 Form of Non-Employee Director Restricted Stock Agreement (incorporated by reference to Exhibit 99.5 of Halliburton's Form S-8 filed May 21, 2009, Registration No. 333-159394).

10.32 First Amendment to Halliburton Company Supplemental Executive Retirement Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed September 21, 2009, File No. 1-3492).

10.33 Amendment No. 1 to Halliburton Company Benefit Restoration Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.2 to Halliburton's Form 8-K filed September 21, 2009, File No. 1-3492).

10.34 Halliburton Annual Performance Pay Plan, as amended and restated effective January 1, 2010 (incorporated by reference to Exhibit 10.3 to Halliburton's Form 8-K filed September 21, 2009, File No. 1-3492).

10.35 Executive Agreement (Evelyn M. Angelle) (incorporated by reference to Exhibit 10.34 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).

10.36 Executive Agreement (Timothy J. Probert) (incorporated by reference to Exhibit 10.36 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).

10.37 Executive Agreement (Craig W. Nunez) (incorporated by reference to Exhibit 10.37 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).

10.38 Amendment to Executive Employment Agreement (James S. Brown) (incorporated by reference to Exhibit 10.39 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).

10.39 Amendment to Executive Employment Agreement (Albert O. Cornelison) (incorporated by reference to Exhibit 10.40 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).

10.40 Amendment to Executive Employment Agreement (Mark A. McCollum) (incorporated by reference to Exhibit 10.43 to Halliburton's Form 10-K for the year ended December 31, 2008, File No. 1-3492).

*	10.41	Amendment No. 1 to 2008 Halliburton Elective Deferral Plan, as amended and restated effective January 1, 2008.
*	10.42	Executive Agreement (Joseph F. Andolino).
*	10.43	Executive Agreement (Joe D. Rainey).
*	12.1	Statement of Computation of Ratio of Earnings to Fixed Charges.
*	21.1	Subsidiaries of the Registrant.
*	23.1	Consent of KPMG LLP.
*	24.1	Powers of attorney for the following directors: Alan M. Bennett James R. Boyd Milton Carroll Nance K. Dicciani S. Malcolm Gillis James T. Hackett Abdallah S. Jum'ah Robert A. Malone J. Landis Martin Debra L. Reed
*	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**	32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**	32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*	99.1	Mine Safety Disclosure.
**	101.INS	XBRL Instance Document
**	101.SCH	XBRL Taxonomy Extension Schema Document
**	101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
**	101.LAB	XBRL Taxonomy Extension Label Linkbase Document
**	101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
**	101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Filed with this Form 10-K.

** Furnished with this Form 10-K.

SIGNATURES

As required by Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has authorized this report to be signed on its behalf by the undersigned authorized individuals on this 17th day of February, 2011.

HALLIBURTON COMPANY

By /s/ David J. Lesar

David J. Lesar
Chairman of the Board,
President, and Chief Executive Officer

As required by the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities indicated on this 17th day of February, 2011.

Signature	Title
/s/ David J. Lesar David J. Lesar	Chairman of the Board, President, Chief Executive Officer, and Director
/s/ Mark A. McCollum Mark A. McCollum	Executive Vice President and Chief Financial Officer
/s/ Evelyn M. Angelle Evelyn M. Angelle	Senior Vice President and Chief Accounting Officer

Signature	Title
* Alan M. Bennett Alan M. Bennett	Director
* James R. Boyd James R. Boyd	Director
* Milton Carroll Milton Carroll	Director
* Nance K. Dicciani Nance K. Dicciani	Director
* S. Malcolm Gillis S. Malcolm Gillis	Director
* James T. Hackett James T. Hackett	Director
* Abdallah S. Jum'ah Abdallah S. Jum'ah	Director
* Robert A. Malone Robert A. Malone	Director
* J. Landis Martin J. Landis Martin	Director
* Debra L. Reed Debra L. Reed	Director

* /s/ Christina M. Ibrahim

Christina M. Ibrahim,
Attorney-in-fact