HALLIBURTON CO
Form 10-K
February 24, 2015

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, 2014
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. [X]

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 Halliburton Company Common Stock held by nonaffiliates on June 30, 2014, determined using the per share closing price on the New York Stock Exchange Composite tape of $71.01 on that date, was approximately $60,180,000,000.

As of February 17, 2015, there were 849,671,830 shares of Halliburton Company Common Stock, $2.50 par value per share, outstanding.

Portions of the Halliburton Company Proxy Statement for our 2015 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, 2014

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 are a leading provider of services and products to 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. 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:

- our Completion and Production segment delivers cementing, stimulation, intervention, pressure control, specialty chemicals, artificial lift, and completion products and services. The segment consists of Production Enhancement, Cementing, Completion Tools, Boots & Coots, Multi-Chem, and Artificial Lift.
- our Drilling and Evaluation segment provides field and reservoir modeling, drilling, evaluation, and precise wellbore placement solutions that enable customers to model, measure, drill, and optimize their well construction activities. The segment consists of Baroid, Sperry Drilling, Wireline and Perforating, Drill Bits and Services, Landmark Software and Services, Testing and Subsea, and Consulting and Project Management.

See Note 3 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. We have significant manufacturing operations in various locations, including the United States, Canada, China, Malaysia, Singapore, and the United Kingdom.

Pending Acquisition of Baker Hughes

On November 16, 2014, we and Baker Hughes Incorporated ("Baker Hughes") entered into a merger agreement under which, subject to the conditions set forth in the merger agreement, we will acquire all the outstanding shares of Baker Hughes in a stock and cash transaction. Baker Hughes is a leading supplier of oilfield services, products, technology and systems to the worldwide oil and natural gas industry. The acquisition is expected to close in the second half of 2015. See Note 2 to the consolidated financial statements for further information about the pending acquisition.

Business strategy

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

- create a balanced portfolio of services and products supported by global infrastructure and anchored by technological innovation to further differentiate our company;
- reach a distinguished level of operational excellence that reduces costs and creates real value;
- preserve a dynamic workforce by being a preferred employer to attract, develop, and retain the best global talent; and
- uphold our strong ethical and business standards, 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 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 2014, 2013, and 2012, based on the location of services provided and products sold, 51%, 49%, and 53% 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 3 to the consolidated financial statements for additional financial information about our geographic operations in the last three years. Because the markets for our services and products are vast and cross numerous geographic lines, it is not practicable to provide a meaningful estimate of the total number of our competitors. The industries we serve are highly competitive, and we have many substantial competitors. Most 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, foreign currency exchange restrictions, and highly inflationary currencies, as well as other geopolitical factors. We believe the geographic diversification of our business activities reduces the risk that loss of operations in any one country, other than the United States, would significantly impact 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 14 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 our 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 proppants, hydrochloric acid, and gels, including guar gum (a blending additive used in our hydraulic fracturing process). We are always seeking ways to ensure the availability of resources, as well as manage costs of raw materials. Our procurement department uses our size and buying power to enhance our access to key materials at competitive prices.

Research and development costs

We maintain an active research and development program. The program improves products, processes, and engineering standards and practices that serve the changing needs of our customers, such as those related to high pressure and high temperature environments, and also develops new products and processes. Our expenditures for research and development activities were $601 million in 2014, $588 million in 2013, and $460 million in 2012. We sponsored over 95% of these expenditures 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 technology covered by patents owned by others, and we license others to utilize technology covered by our patents. 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 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;
- 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.

Additionally, customer spending patterns for software and various other oilfield services and products can result in higher activity in the fourth quarter of the year.

Employees

At December 31, 2014, we employed more than 80,000 people worldwide compared to approximately 77,000 at December 31, 2013. At December 31, 2014, approximately 16% 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 9 to the consolidated financial statements and Item 1(a), “Risk Factors.”

Hydraulic fracturing process

Hydraulic fracturing is a process that creates fractures extending from the well bore into the rock formation to enable natural gas or oil to move more easily from the rock pores to a production conduit. A significant portion of our Completion and Production segment provides hydraulic fracturing services to customers developing shale natural gas and shale oil. From time to time, questions arise about the scope of our operations in the shale natural gas and shale oil sectors, and the extent to which these operations may affect human health and the environment.

We sometimes design and generally implement a hydraulic fracturing operation to 'stimulate' the well's production, at the direction of our customer, once the well has been drilled, cased, and cemented. Our customer is generally responsible for providing the base fluid (usually water) used in the hydraulic fracturing of a well. We supply the proppant (often sand) and at least a portion of the additives used in the overall fracturing fluid mixture. In addition, we mix the additives and proppant with the base fluid and pump the mixture down the wellbore to create the desired fractures in the target formation. The customer is responsible for disposing of any materials that are subsequently produced or pumped out of the well, including flowback fluids and produced water.

As part of the process of constructing the well, the customer will take a number of steps designed to protect drinking water resources. In particular, the casing and cementing of the well are designed to provide 'zonal isolation' so that the fluids pumped down the wellbore and the oil and natural gas and other materials that are subsequently pumped out of the well will not come into contact with shallow aquifers or other shallow formations through which those materials could potentially migrate to freshwater aquifers or the surface.

The potential environmental impacts of hydraulic fracturing have been studied by numerous government entities and others. In 2004, the United States Environmental Protection Agency (EPA) conducted an extensive study of hydraulic fracturing practices, focusing on coalbed methane wells, and their potential effect on underground sources of drinking water. The EPA’s study concluded that hydraulic fracturing of coalbed methane wells poses little or no threat to underground sources of drinking water. At the request of Congress, the EPA is currently undertaking another study of the relationship between hydraulic fracturing and drinking water resources that will focus on the fracturing of shale natural gas wells.

We have made detailed information regarding our fracturing fluid composition and breakdown available on our internet web site at www.halliburton.com. We also have proactively developed processes to provide our customers with the chemical constituents of our hydraulic fracturing fluids to enable our customers to comply with state laws as well as voluntary standards established by the Chemical Disclosure Registry, www.fracfocus.org.

At the same time, we have invested considerable resources in developing our CleanSuite™ hydraulic fracturing technologies, which offer our customers a variety of especially environment-friendly alternatives related to the use of hydraulic fracturing fluid additives and other aspects of our hydraulic fracturing operations. We created a hydraulic fracturing fluid system comprised of materials sourced entirely from the food industry. In addition, we have engineered a process that uses ultraviolet light to control the growth of bacteria in hydraulic fracturing fluids, allowing customers to minimize the use of chemical biocides. We are committed to the continued development of innovative chemical and mechanical technologies that allow for more economical and environmentally friendly development of the world’s oil and natural gas reserves.

In evaluating any environmental risks that may be associated with our hydraulic fracturing services, it is helpful to understand the role that we play in the development of shale natural gas and shale oil. Our principal task generally is to manage the process of injecting fracturing fluids into the borehole to 'stimulate' the well. Thus, based on the provisions in our contracts and applicable law, the primary environmental risks we face are potential pre-injection spills or releases of stored fracturing fluids and potential spills or releases of fuel or other fluids associated with pumps, blenders, conveyors, or other above-ground equipment used in the hydraulic fracturing process.

Although possible concerns have been raised about hydraulic fracturing operations, the circumstances described above have helped to mitigate those concerns. To date, we have not been obligated to compensate any indemnified party for any environmental liability arising directly from hydraulic fracturing, although there can be no assurance that such obligations or liabilities will not arise in the future.

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, 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 web 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 2014, 2013, or 2012. 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 24, 2015, including all offices and positions held by each in the past five years:

	Name and Age	Offices Held and Term of Office
	James S. Brown (Age 60)	President, Western Hemisphere of Halliburton Company, since January 2008
*	Christian A. Garcia (Age 51)	Senior Vice President, Finance and Acting Chief Financial Officer of Halliburton Company, since January 2015
		Senior Vice President and Chief Accounting Officer of Halliburton Company, January 2014 to December 2014
		Senior Vice President and Treasurer of Halliburton Company, September 2011 to December 2013
		Senior Vice President, Investor Relations of Halliburton Company, January 2011 to August 2011
		Vice President, Investor Relations of Halliburton Company, December 2007 to December 2010
	Charles E. Geer, Jr. (Age 44)	Vice President and Corporate Controller of Halliburton Company, since January 2015
		Vice President, Finance of Halliburton Company, December 2013 to December 2014
		Vice President and Chief Accounting Officer of Select Energy Services, April 2011 to November 2013
		Vice President and Principal Accounting Officer of Weatherford International, June 2010 to March 2011
		Corporate Controller of Weatherford International, September 2007 to May 2010
	Myrtle L. Jones (Age 55)	Senior Vice President, Tax of Halliburton Company, since March 2013
		Senior Managing Director of Tax and Internal Audit, Service Corporation International, February 2008 to February 2013
*	David J. Lesar (Age 61)	Chairman of the Board and Chief Executive Officer of Halliburton Company, since August 2014
		Chairman of the Board, President, and Chief Executive Officer of Halliburton Company, August 2000 to July 2014
	Mark A. McCollum (Age 55)	Executive Vice President and Chief Integration Officer of Halliburton Company, since January 2015
		Executive Vice President and Chief Financial Officer of Halliburton Company, January 2008 to December 2014
	Timothy M. McKeon (Age 42)	Vice President and Treasurer of Halliburton Company, since January 2014
		Assistant Treasurer of Halliburton Company, September 2011 to December 2013
		Director of Finance, Drilling & Evaluation Division of Halliburton Company, February 2011 to August 2011

	Director of Treasury Operations of Halliburton Company, March 2009 to January 2011
* Jeffrey A. Miller (Age 51)	President of Halliburton Company, since August 2014 Executive Vice President and Chief Operating Officer of Halliburton Company, September 2012 to July 2014

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		Senior Vice President, Global Business Development and Marketing of Halliburton Company, January 2011 to August 2012 Senior Vice President, Gulf of Mexico Region of Halliburton Company, January 2010 to December 2010
*	Lawrence J. Pope (Age 46)	Executive Vice President of Administration and Chief Human Resources Officer of Halliburton Company, since January 2008
	Joe D. Rainey (Age 58)	President, Eastern Hemisphere of Halliburton Company, since January 2011 Senior Vice President, Eastern Hemisphere of Halliburton Company, January 2010 to December 2010
*	Robb L. Voyles (Age 57)	Executive Vice President and General Counsel of Halliburton Company, since January 2014 Senior Vice President, Law of Halliburton Company, September 2013 to December 2013 Partner, Baker Botts L.L.P., January 1989 to August 2013

* 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.

Our ability to complete the Baker Hughes acquisition is subject to various closing conditions, including the approval of Baker Hughes and our stockholders and the receipt of consents and approvals from governmental authorities, which may impose conditions that could adversely affect us or cause the acquisition to be abandoned.

To complete the acquisition, our stockholders must approve the issuance of shares of our common stock as contemplated by the merger agreement, and Baker Hughes stockholders must adopt the merger agreement. In addition, we and Baker Hughes must also make certain filings with and obtain certain consents and approvals from various governmental and regulatory authorities.

We have not yet obtained the regulatory consents and approvals required to complete the acquisition. Governmental or regulatory agencies could seek to block or challenge the acquisition. Even if these regulatory consents and approvals are obtained, the governmental authorities from which these approvals are required may impose conditions on the completion of the acquisition, including requiring significant divestitures, that could have an adverse effect on the combined company following the acquisition. We will be unable to complete the acquisition until the waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act, as amended, and the rules promulgated thereunder by the Federal Trade Commission have expired or been terminated and consents and approvals are received from the European Commission and various other governmental authorities (jointly, the “Regulatory Clearances”). Additionally, even after the statutory waiting period under the antitrust laws and even after completion of the acquisition, governmental authorities could seek to block or challenge the acquisition as they deem necessary or desirable in the public interest. In addition, in some jurisdictions, a competitor, customer or other third party could initiate a private action under the antitrust laws challenging or seeking to enjoin the acquisition, before or after it is completed. Baker Hughes or Halliburton may not prevail and may incur significant costs in defending or settling any action under the antitrust laws. The merger agreement may require us to accept conditions from these regulators that could adversely impact the combined company. If we agree to undertake divestitures or comply with operating restrictions in order to obtain any approvals required to complete the acquisition, we may be less able to realize anticipated benefits of the acquisition, and the business and results of operations of the combined company after the acquisition may be adversely affected. If the Regulatory Clearances are not received, or they are not received on terms that satisfy the conditions set forth in the merger agreement, then neither we nor Baker Hughes will be obligated to complete the acquisition.

If we and Baker Hughes are unable to complete the acquisition, we would be subject to a number of risks, including the following:

- we would not realize the anticipated benefits of the acquisition, including, among other things, increased operating efficiencies;
- the attention of our management may have been diverted to the acquisition rather than to our own operations and the pursuit of other opportunities that could have been beneficial to us;
- the potential loss of key personnel during the pendency of the acquisition as employees may experience uncertainty about their future roles with the combined company;
- we will have been subject to certain restrictions on the conduct of our business, which may prevent us from making certain acquisitions or dispositions or pursuing certain business opportunities while the acquisition is pending; and
- the trading price of our common stock may decline to the extent that the current market prices reflect a market assumption that the acquisition will be completed.

If the acquisition is not completed, our ongoing businesses may be adversely affected. Under the merger agreement, we could be required, under certain circumstances, to pay Baker Hughes a termination fee of $1.5 billion or, in certain circumstances where the termination of the merger agreement is related to failures to obtain the Regulatory Clearances, $3.5 billion. If such a termination fee is payable, the payment of this fee could have material and adverse consequences to the financial condition and operations of Halliburton.

We can provide no assurance that the various closing conditions will be satisfied and that the necessary Regulatory Clearances and other approvals will be obtained, or that any required conditions will not materially adversely affect the combined company following the acquisition. In addition, we can provide no assurance that these conditions will not result in the abandonment or delay of the acquisition. The occurrence of any of these events individually or in combination could have a material adverse effect on our results of operations and the trading price of our common stock.

Pending litigation against us and Baker Hughes could result in an injunction preventing the consummation of the acquisition or may adversely affect our business, financial condition or results of operations following the acquisition. Following the announcement of the acquisition, various lawsuits have been filed in the Court of Chancery of the State of Delaware and the U.S. District Court for the Southern District of Texas against Baker Hughes, the members of the Baker Hughes Board, and us, alleging breaches of various fiduciary duties by the members of the Baker Hughes Board during the acquisition negotiations and by entering into the merger agreement and approving the acquisition and alleging that we and Baker

Hughes aided and abetted such alleged breaches of fiduciary duties. Among other remedies, the plaintiffs seek to enjoin the acquisition and rescind the merger agreement, in addition to certain unspecified damages and reimbursement of costs. While we and Baker Hughes believe these suits are without merit and intend to vigorously defend against such claims, the outcome of any such litigation is inherently uncertain. The defense or settlement of any lawsuit or claim that remains unresolved at the time the acquisition closes may adversely affect the combined company's business, financial condition or results of operation.

Our stockholders will have a reduced ownership and voting interest after the Baker Hughes acquisition and will exercise less influence over management of the combined company.
Our stockholders currently have the right to vote for our board of directors and on other matters affecting the company. When the acquisition occurs, each Baker Hughes stockholder that receives shares of our common stock will become a stockholder of ours and correspondingly, each of our stockholders will remain a stockholder of Halliburton Company with a percentage ownership of the combined company that is significantly smaller than the stockholder's percentage ownership prior to the acquisition. Upon completion of the acquisition, former Baker Hughes stockholders are expected to hold approximately 37% of our common stock. As a result of these reduced ownership percentages, our stockholders will have less influence on the management and policies of the combined company than they now have with respect to Halliburton Company.

We will incur significant transaction, acquisition-related and restructuring costs in connection with the Baker Hughes acquisition and the combined company could incur substantial expenses related to the integration of Baker Hughes.
We expect to incur costs associated with combining our operations and the operations of Baker Hughes, as well as transaction fees and other costs related to the acquisition. Many of these costs will be borne by us even if the acquisition is not completed. We will incur through completion of the acquisition, and the combined company will incur following the completion of the acquisition, substantial expenses in connection with integrating each company's respective businesses, policies, procedures, operations, technologies and systems. There are a large number of systems that must be integrated, including information management, purchasing, accounting and finance, sales, billing, payroll and benefits, fixed asset and lease administration systems and regulatory compliance. Many of the expenses that will be incurred, by their nature, are difficult to estimate accurately at the present time. These expenses could, particularly in the near term, reduce the savings that we expect to achieve from the elimination of duplicative expenses and the realization of economies of scale and cost savings related to the integration of the businesses following the completion of the acquisition, and accordingly, any net benefits may not be achieved in the near term or at all. These integration expenses may result in significant charges taken against earnings by us prior to completion of the acquisition and by the combined company following the completion of the acquisition.

The market value of our common stock could decline if large amounts of our common stock are sold following the Baker Hughes acquisition.
Following the acquisition, our stockholders and former stockholders of Baker Hughes will own interests in a combined company operating an expanded business with more assets and a different mix of liabilities. Our current stockholders and the current stockholders of Baker Hughes may not wish to continue to invest in the combined company, or may wish to reduce their investment in the combined company, in order to comply with institutional investing guidelines, to increase diversification or to track any rebalancing of stock indices in which our or Baker Hughes common stock is or was included. If, following the acquisition, large amounts of our common stock are sold, the price of our common stock could decline.

The Baker Hughes acquisition may not be accretive, and may be dilutive, to our earnings per share in the near term, which may negatively affect the market price of our common stock.
We anticipate that the acquisition may not be accretive, and may be dilutive, to earnings per share until the end of the second calendar year after closing. This expectation is based on preliminary estimates that may materially change. In addition, future events and conditions could decrease or delay any accretion, result in dilution or cause greater dilution

than is currently expected, including:
- adverse changes in energy market conditions;
- commodity prices for oil, natural gas and natural gas liquids;
- production levels;
- operating results;
- competitive conditions;
- laws and regulations affecting the energy business;
- capital expenditure obligations;
- higher than expected integration costs;
- lower than expected synergies; and
- general economic conditions.

Any dilution of, or decrease or delay of any accretion to, our earnings per share could cause the price of our common stock to decline.

The combined Halliburton and Baker Hughes company will record goodwill that could become impaired and adversely affect the combined company’s operating results.

The acquisition will be accounted for as an acquisition by us in accordance with accounting principles generally accepted in the United States. Under the acquisition method of accounting, the assets and liabilities of Baker Hughes will be recorded, as of the acquisition closing date, at their respective fair values and added to those of Halliburton. Our reported financial condition and results of operations issued after completion of the acquisition will reflect Baker Hughes balances and results after completion of the acquisition, but will not be restated retroactively to reflect the historical financial position or results of operations of Baker Hughes for periods prior to the acquisition. Under the acquisition method of accounting, the total purchase price will be allocated to Baker Hughes’s tangible assets and liabilities and identifiable intangible assets based on their fair values as of the acquisition closing date. The excess of the purchase price over those fair values will be recorded as goodwill. We and Baker Hughes expect that the acquisition will result in the creation of goodwill based upon the application of the acquisition method of accounting. To the extent the value of goodwill or intangibles becomes impaired, the combined company may be required to incur material charges relating to such impairment. Such a potential impairment charge could have a material adverse impact on the combined company’s operating results.

The pendency of the Baker Hughes acquisition could adversely affect us.

In connection with the pending acquisition, some of our suppliers and customers may delay or defer sales and purchasing decisions, which could negatively impact revenues, earnings and cash flows regardless of whether the acquisition is completed. We have agreed in the merger agreement to refrain from taking certain actions with respect to our business and financial affairs during the pendency of the acquisition, which restrictions could be in place for an extended period of time if completion of the acquisition is delayed and could adversely impact our financial condition, results of operations or cash flows.

The combined Halliburton and Baker Hughes enterprise’s indebtedness following the acquisition will be greater than Halliburton’s existing indebtedness. Therefore, it may be more difficult for the combined enterprise to pay or refinance its debts or take other actions, and the combined enterprise may need to divert its cash flow from operations to debt service payments.

In connection with the acquisition, we will incur additional debt to pay the merger consideration and transaction expenses and the indebtedness of the combined enterprise will increase as a result of Baker Hughes’s outstanding debt. Halliburton’s total liabilities as of December 31, 2014 were approximately $15.9 billion, including $7.8 billion of long-term debt. Baker Hughes’s total liabilities as of December 31, 2014 were approximately $10.1 billion, including $3.9 billion of long-term debt. We currently expect to incur additional debt in connection with financing the cash portion of the merger consideration. See Note 7 to the consolidated financial statements for further information about debt financing for the pending acquisition. The combined enterprise’s debt service obligations with respect to this increased indebtedness could have an adverse impact on its earnings and cash flows, which after the acquisition would include the earnings and cash flows of Baker Hughes, for as long as the indebtedness is outstanding.

The combined enterprise’s increased indebtedness could also have important consequences to holders of our common stock. For example, it could:

- make it more difficult for the combined enterprise to pay or refinance its debts as they become due during adverse economic and industry conditions because any decrease in revenues could cause the combined enterprise to not have sufficient cash flows from operations to make its scheduled debt payments;
- limit the combined enterprise’s flexibility to pursue other strategic opportunities or react to changes in its business and the industry in which it operates and, consequently, place the combined enterprise at a competitive disadvantage to its competitors with less debt;
- require a substantial portion of the combined enterprise’s cash flows from operations to be used for debt service payments, thereby reducing the availability of its cash flow to fund working capital, capital expenditures, acquisitions, dividend payments and other general corporate purposes;

- result in a downgrade in the rating of our indebtedness, which could limit our ability to borrow additional funds and increase the interest rates applicable to our indebtedness (after the announcement of the acquisition, Standard & Poor's Ratings Services placed all of our ratings on negative watch, and all of Baker Hughes's ratings on negative watch);
- result in higher interest expense in the event of increases in interest rates since some of our borrowings are, and will continue to be, at variable rates of interest; or
- require the combined enterprise to repatriate foreign earnings to meet liquidity demands, resulting in a tax payment that may not be accrued for.

Based upon current levels of operations, we expect the combined enterprise to be able to generate sufficient cash on a consolidated basis to make all of the principal and interest payments when such payments are due under our existing credit facilities, indentures and other instruments governing our outstanding indebtedness, and the indebtedness of Baker Hughes that may remain outstanding after the acquisition, but there can be no assurance that the combined enterprise will be able to repay or refinance such borrowings and obligations.

Following the Baker Hughes acquisition, the combined company may encounter difficulties in integrating Halliburton's and Baker Hughes's businesses and realizing the anticipated benefits of the acquisition.
The acquisition involves the combination of two companies which currently operate as independent public companies. The combined company will be required to devote management attention and resources to integrating its business practices and operations, and prior to the acquisition, management attention and resources will be required to plan for such integration. Potential difficulties the combined company may encounter in the integration process include the following:

- the inability to successfully integrate the respective businesses of the two companies in a manner that permits the combined company to achieve the cost savings and operating synergies anticipated to result from the acquisition, which could result in the anticipated benefits of the acquisition not being realized partly or wholly in the time frame currently anticipated or at all;
- lost sales and customers as a result of certain customers of either or both of the two companies deciding not to do business with the combined company, or deciding to decrease their amount of business in order to reduce their reliance on a single company;
- integrating personnel from the two companies while maintaining focus on providing consistent, high quality products and services;
- potential unknown liabilities and unforeseen increased expenses, delays or regulatory conditions associated with the acquisition; and
- performance shortfalls at one or both of the two companies as a result of the diversion of management’s attention caused by completing the acquisition and integrating the companies’ operations.

Liabilities arising out of the Macondo well incident 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 the lease operator, BP Exploration and Production, Inc. (BP Exploration), an 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. Numerous lawsuits relating to the Macondo well incident were filed against us, BP, Transocean and others in federal and state courts throughout the United States, most of which have been consolidated in a Multi-District Litigation (MDL) proceeding, and additional lawsuits may be filed against us. In addition, the Bureau of Safety and Environmental Enforcement has issued a notification of Incidents of Noncompliance (INCs) to us relating to the Macondo well incident. We understand that regulations in effect at the time of the alleged violations provide for fines of up to $35,000 per day per violation.
Our contract with BP relating to the Macondo well generally provides for our indemnification by BP for certain claims and expenses relating to the Macondo well incident. The MDL court has ruled that BP is required to indemnify us for third-party compensatory claims, or actual damages, that arise from pollution or contamination that did not originate from our property or equipment located above the surface of the land or water. The court also held, however, that BP does not owe us indemnity for punitive damages or for civil penalties under the Clean Water Act (CWA), if any.
In September 2014, we reached an agreement, subject to court approval, to settle a substantial portion of the plaintiffs’ claims asserted against us relating to the Macondo well incident (our MDL Settlement). Certain conditions must be satisfied before our MDL Settlement becomes effective, and our MDL Settlement does not cover all claims asserted

against us in the MDL. Subsequently in September 2014, the MDL court ruled (Phase One Ruling) that, among other things, (1) in relation to the Macondo well incident, BP’s conduct was reckless, Transocean’s conduct was negligent, and our conduct was negligent, (2) fault for the Macondo blowout, explosion, and spill is apportioned 67% to BP, 30% to Transocean, and 3% to us, and (3) the indemnity and release clauses in our contract with BP are valid and enforceable against BP. The MDL court did not find that our conduct was grossly negligent. In January 2015, the MDL court ruled that, giving effect to the amount of oil collected as a result of BP’s cleanup efforts, a total of 3.19 million barrels of oil were discharged into the Gulf of Mexico for the purposes of determining the maximum penalty under the CWA. Although we have not been charged with any violations under the CWA, BP has filed claims against us, which remain unresolved, for equitable contribution, indemnity and subrogation with respect to its liabilities under the Oil Pollution Act of 1990 and CWA. Under the CWA, civil penalties of up to $1,100 per barrel of oil discharged (or $4,300 per barrel in the case of those found to have been grossly negligent) may be assessed against responsible parties.

For additional information relating to our MDL Settlement, the status of the MDL and the INCs, see Note 9 to the consolidated financial statements.
As of December 31, 2014, our existing loss contingency liability related to the Macondo well incident was $805 million, consisting of a current portion of $367 million and a non-current portion of $439 million. The $805 million represents a $733 million loss contingency related to our MDL Settlement as well as an additional loss contingency of $72 million unrelated to that settlement. Our loss contingency liability does not include potential recoveries from our insurers or indemnification by BP.
Because our MDL Settlement is subject to court approval and other conditions and the Phase One Ruling and other rulings of the MDL court are subject to appeals, we are unable to predict the ultimate outcome of the many lawsuits, investigations, and other matters relating to the Macondo well incident, including appeals of the Phase One Ruling, further orders and rulings of the MDL court and other courts, and indemnification and insurance arrangements. BP has filed a Notice of Appeal for the Phase One Ruling and the MDL court's denial of its motion to amend the court's findings, alter or amend the court's judgment, or for a new trial. In addition, certain insurance carriers have notified us that they do not intend to reimburse us for any amounts with respect to our MDL Settlement, representing approximately $200 million of insurance coverage. We are unable to predict whether or when the court will approve our MDL Settlement or whether or when the conditions of our MDL Settlement will be satisfied.
As a result of the various potential developments relating to the Macondo well incident, there are additional loss contingencies relating to the Macondo well incident that are reasonably possible but for which we cannot make a reasonable estimate. Accordingly, we may adjust our estimated loss contingency liability and our amounts recoverable from insurance in the future. In addition, applicable accounting rules and guidance may require us to recognize a loss contingency for which we may be fully indemnified, without recognizing a corresponding receivable for the amount of the indemnity payment. Depending on the outcome of the various potential developments relating to the Macondo well incident, liabilities arising out of the incident 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, risk of government actions, and cyber-attacks that could have a material adverse effect on our business, 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 business, 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, other armed conflict, and sanctions;
  - inflation; and
  - currency fluctuations, devaluations, and conversion restrictions; and
- 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 or our operations, 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 operations, revenue, and profits are subject to the adverse consequences of war, the effects of terrorism, civil unrest, strikes, currency controls, and governmental actions. These and other risks described above could result in the loss of our personnel or assets, cause us to evacuate our personnel from certain countries, cause us to increase spending on security worldwide, disrupt financial and commercial markets, including the supply of and pricing for oil and natural gas, and generate greater political and economic instability in some of the geographic areas in which we operate. Areas where we operate that have significant risk include, but are not limited to: the Middle East, North Africa, Angola, Azerbaijan, Colombia, Indonesia, Kazakhstan, Mexico, Nigeria, Russia, and Venezuela. In addition, any possible reprisals as a consequence of military or other action, such as acts of terrorism in the United States or elsewhere, could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition.

Our operations are becoming increasingly dependent on digital technologies and services. We use these technologies for internal purposes, including data storage, processing, and transmissions, as well as in our interactions with customers and suppliers. Digital technologies are subject to the risk of cyber-attacks. If our systems for protecting against cybersecurity risks prove not to be sufficient, we could be adversely affected by, among other things: loss of or damage to intellectual property, proprietary or confidential information, or customer, supplier, or employee data; interruption of our business operations; and increased costs required to prevent, respond to, or mitigate cybersecurity attacks. These risks could harm our reputation and our relationships with customers, suppliers, employees, and other third parties, and may result in claims against us. In addition, these risks could have a material adverse effect on our business, 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, violations of which could have a material adverse effect on our business, 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 United States Foreign Corrupt Practices Act (FCPA), which prohibits United States companies and 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 our employees, agents, or joint venture partners that could be in violation of anti-corruption laws, even though these parties are not 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 may result in internal, independent, or government investigations. Violations of anti-corruption laws 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, the shipment of goods, services, and technology across international borders subjects us to extensive trade laws and regulations. Our import activities are governed by the unique customs laws and regulations in each of the countries where we operate. Moreover, many countries, including the United States, control the export and re-export of certain goods, services and technology and impose related export recordkeeping and reporting obligations. Governments may also impose economic sanctions against certain countries, persons, and entities that may restrict or prohibit transactions involving such countries, persons and entities, which may limit or prevent our conduct of business in certain jurisdictions. During 2014, the United States and European Union imposed sectoral sanctions directed at Russia's oil and gas industry. Among other things, these sanctions restrict the provision of goods, services, and technology in support of exploration or production for deep water, Arctic offshore, or shale projects that have the potential to produce oil in Russia. These sanctions resulted in our winding down and ending work on two projects in Russia in 2014, and have prevented us from pursuing certain other projects in Russia. Any expansion of sanctions against Russia's oil and gas industry could further hinder our ability to do business in Russia, which could have a material adverse effect on our consolidated results of operations.

The laws and regulations concerning import activity, export recordkeeping and reporting, export control, and economic sanctions are complex and constantly changing. These laws and regulations can cause delays in shipments and unscheduled operational downtime. Moreover, any failure to comply with applicable legal and regulatory trading obligations could result in criminal and civil penalties and sanctions, such as fines, imprisonment, debarment from governmental contracts, seizure of shipments and loss of import and export privileges. 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, consolidated results of operations, and consolidated financial condition. 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.

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 effect on our business and 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.

The adoption of any future federal, state, or local laws or implementing regulations imposing reporting obligations on, or limiting or banning, 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. Various federal legislative and regulatory initiatives have been undertaken which could result in additional requirements or restrictions being imposed on hydraulic fracturing operations. For example, the Department of Interior has issued proposed regulations that would apply to hydraulic fracturing operations on wells that are subject to federal oil and gas leases and that would impose requirements regarding the disclosure of chemicals used in the hydraulic fracturing process as well as requirements to obtain certain federal approvals before proceeding with hydraulic fracturing at a well site. These regulations, if adopted, would establish additional levels of regulation at the federal level that could lead to operational delays and increased operating costs. At the same time, legislation and/or regulations have been adopted in several states that require additional disclosure regarding chemicals used in the hydraulic fracturing process but that generally include protections for proprietary information. Legislation and/or regulations are being considered at the state and local level that could impose further chemical disclosure or other regulatory requirements (such as restrictions on the use of certain types of chemicals or prohibitions on hydraulic fracturing operations in certain areas) that could affect our operations. Two states (New York and Vermont) have banned or are in the process of banning the use of high volume hydraulic fracturing. Local jurisdictions in some states have adopted ordinances that restrict or in certain cases prohibit the use of hydraulic fracturing for oil and gas development. In addition, governmental authorities in various foreign countries where we have provided or may provide hydraulic fracturing services have imposed or are considering imposing various restrictions or conditions that may affect hydraulic fracturing operations.

The adoption of any future federal, state, local, or foreign laws or implementing regulations imposing reporting obligations on, or limiting or banning, 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.

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. 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.

Failure on our part to comply with, and the costs of compliance with, applicable health, safety, and environmental requirements could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition

Our business is subject to a variety of health, safety, and 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. Applicable regulatory 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;
- the use of underground injection wells; and
- the protection of worker safety both onshore and offshore.

These and other requirements generally are becoming increasingly strict. Sanctions for failure to comply with the 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 regulatory compliance, including compliance with changes in or expansion of applicable regulatory requirements, which could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

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 related to greenhouse gases and climate change 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 demand for oil and natural gas. Likewise, such restrictions may result in additional compliance obligations with respect to the release, capture, sequestration, and use of carbon dioxide that could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

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 business, 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. Crude oil prices declined significantly in the second half of 2014, and were negatively affected by a combination of factors, including weakening demand in Europe and Asia, increased production in the United States, and the decision in late November by the Organization of Petroleum Exporting Countries to keep production levels unchanged. Additionally, stronger economic performance in the United States has led to a strengthening in the U.S. dollar relative to most other currencies, contributing further to the fall in the U.S. dollar value of oil. Downward pressure on commodity prices has continued in early 2015 and could continue for the foreseeable future. We anticipate 2015 will be a challenging year for us, as our customers continue to make downward revisions to their operating budgets. Therefore, we expect a drop-off in activity coupled with pricing pressures, and corresponding reductions in revenue and operating margins in 2015. For more information, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations - Business Environment and Results of Operations.” 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 business, consolidated results of operations, and consolidated financial condition. Additionally, a prolonged reduction in oil and natural gas prices may require us to record asset impairments, including an impairment of the carrying value of our goodwill. Such a potential impairment charge could have a material adverse impact on our operating results. 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:

- the level of supply and demand for oil and natural gas, especially demand for natural gas in the United States;
- governmental regulations, including the policies of governments regarding the exploration for and production and development of their oil and natural gas reserves;
- 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; and
- potential acceleration of the development of alternative fuels.

Our business is dependent on capital spending by our customers, and reductions in capital spending could have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition.
Our business is directly affected by changes in capital expenditures by our customers, and reductions in their capital spending could reduce demand for our services and products and have a material adverse effect on our business, consolidated results of operations, and consolidated financial condition. Some of the items that may impact our customer's capital spending include:

- oil and natural gas prices, including volatility of oil and natural gas prices and expectations regarding future prices;
- the inability of our customers to access capital on economically advantageous terms;
- the consolidation of our customers;
- customer personnel changes; and
- adverse developments in the business or operations of our customers, including write-downs of reserves and borrowing base reductions under customer credit facilities.

As a result of recent decreases in commodity prices, many of our customers have announced reduced capital spending budgets for 2015, and we expect that further reductions in commodity prices or prices remaining at current levels for a prolonged period of time may result in further capital budget reductions in the future.

Our business could be materially and adversely affected by severe or unseasonable weather where we have operations.
Our business could be materially and adversely affected by severe weather, particularly in the Gulf of Mexico, Russia, and the North Sea. Some experts believe global climate change could increase the frequency and severity of extreme weather conditions. Repercussions of severe or unseasonable 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;
- decreases in demand for natural gas during unseasonably warm winters; and
- loss of productivity.

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. 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 currency exchange risks resulting from changes in foreign currency 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 non-traded 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. In addition, we may accumulate cash in foreign jurisdictions that may be subject to taxation if repatriated to the United States. For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Business Environment and Results of Operations" and Note 10 to the Consolidated Financial Statements, "Income Taxes."

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 the market, customer requirements, competitive pressures, and technology trends, 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 the market, customer requirements, competitive pressures, and technology trends, our business and consolidated results of operations could be materially and adversely affected, and the value of our intellectual property may be reduced. Likewise, if our proprietary technologies, equipment, 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.

If our customers delay 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 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, the risk of delayed payments, and currency risks, 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. Any delays in receiving payment on our receivables from our primary customer in Venezuela or failure to pay us a significant amount of our outstanding receivables 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, the foreign currency exchange rate, actions of the Venezuelan government, and general economic conditions such as continued inflation and future customer payments and spending. For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Business Environment and Results of Operations - International operations - Venezuela."

Some of our customers require bids for contracts in the form of long-term, fixed pricing 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.

Some of our customers, primarily NOCs, may require bids for contracts in the form of long-term, fixed pricing contracts that may require us to provide integrated project management services outside our normal discrete business to act as project managers as well as service providers, and may require us to assume additional risks associated with cost over-runs. These customers may provide us with inaccurate information in relation to their reserves, which is a subjective process that involves location and volume estimation, that may result in cost over-runs, 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 issues may also result in cost over-runs, delays, and project losses.

Providing services on an integrated basis may also require us to assume additional risks associated with operating cost inflation, labor availability and productivity, supplier pricing and performance, and potential claims for liquidated damages. We rely on third-party subcontractors and equipment providers to assist us with the completion of these types of contracts. To the extent that we cannot engage subcontractors or acquire equipment or materials in a timely manner and on reasonable terms, our ability to complete a project in accordance with stated deadlines 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 our customers for these delays. This may reduce the profit to be realized or result in a loss on a project.

Constraints in the supply of, prices for, and availability of transportation of raw materials can have a material adverse effect on our business and consolidated results of operations.
Raw materials essential to our business are normally readily available. High levels of demand for, or shortage of, raw materials, such as proppants, hydrochloric acid, and gels, including guar gum, can trigger constraints in the supply chain of those raw materials, particularly where we have a relationship with a single supplier for a particular resource. Many of the raw materials essential to our business require the use of rail, storage, and trucking services to transport the materials to our jobsites. These services, particularly during times of high demand, may cause delays in the arrival of or otherwise constrain our supply of raw materials. These constraints could have a material adverse effect on our business and consolidated results of operations. In addition, price increases imposed by our vendors for raw materials used in our business and the inability to pass these increases through to our customers could have a material adverse effect on our business and consolidated results of operations.

Our acquisitions, dispositions, and investments may not result in anticipated benefits and may present risks not originally contemplated, 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 venture interests. These transactions are intended to (but may not) 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 liquidity, consolidated results of operations, and consolidated financial condition.
These transactions also involve risks, and we cannot ensure that:

- any acquisitions would result in an increase in income or provide an adequate return of capital or other anticipated benefits;
- any acquisitions would be successfully integrated into our operations and internal controls;
- the due diligence conducted 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, or acquisitions, including integration efforts, would not divert management resources; or
- any dispositions, investments, or acquisitions would not have a material adverse effect on our liquidity, consolidated results of operations, or consolidated 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.

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.

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.

Item 1(b). Unresolved Staff Comments.

None.

Item 2. Properties.

We own or lease numerous properties in domestic and foreign locations. Our principal properties include manufacturing facilities, research and development laboratories, technology centers, and corporate offices. All of our owned properties are unencumbered.

The following locations represent our major facilities by segment:

Completion and Production: Arbroath, United Kingdom; Johor Bahru, Malaysia; and Lafayette, Louisiana.

Drilling and Evaluation: Alvarado, Texas; Nisku, Canada; and The Woodlands, Texas.

Shared/corporate facilities: Carrollton, Texas; Denver, Colorado; Dhahran, Saudi Arabia; Dubai, United Arab Emirates (corporate executive offices); Duncan, Oklahoma; Houston, Texas (corporate executive offices); Kuala Lumpur, Malaysia; London, England; Moscow, Russia; Panama City, Panama; Pune, India; Rio de Janeiro, Brazil; Singapore; and Stavanger, Norway.

In addition, we have 174 international and 117 United States field camps from which we deliver our services and products. We also have numerous small facilities that include sales, project, and support 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.

Information related to Item 3. Legal Proceedings is included in Note 9 to the consolidated financial statements.

Item 4. Mine Safety 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 under the Federal Mine Safety and Health Act of 1977. 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 and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 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 our common stock and quarterly dividend payments is included under the caption “Quarterly Data and Market Price Information” on page 75 of this annual report. Quarterly cash dividends on our common stock, which were paid in March, June, September, and December of each year, were $0.125 per share for the first three quarters of 2013, $0.15 per share in the fourth quarter of 2013 and the first three quarters of 2014, and $0.18 per share in the fourth quarter of 2014. The declaration and payment of future dividends will be at the discretion of the Board of Directors and will depend on, among other things, future earnings, general financial condition and liquidity, success in business activities, capital requirements, and general business conditions. Subject to Board of Directors approval, our intention is to pay dividends representing at least 15% to 20% of our net income on an annual basis.

The following graph and table compare total shareholder return on our common stock for the five-year period ended December 31, 2014, with the Philadelphia Oil Service Index (OSX) and the Standard & Poor’s 500 ® Index over the same period. This comparison assumes the investment of $100 on December 31, 2009, and the reinvestment of all dividends. The shareholder return set forth is not necessarily indicative of future performance.

	December 31					
	2009	2010	2011	2012	2013	2014
Halliburton	$ 100.00	$ 137.25	$ 117.09	$ 119.04	$ 176.17	$ 138.12
Philadelphia Oil Service Index (OSX)	100.00	126.92	113.53	117.09	153.76	120.98
Standard & Poor’s 500 ® Index	100.00	115.06	117.49	136.30	180.44	205.14

At February 17, 2015, we had 13,919 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.
The following table is a summary of repurchases of our common stock during the three-month period ended December 31, 2014.

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 (b)	Maximum Number (or Approximate Dollar Value) of Shares that may yet be Purchased Under the Program (b)
October 1 - 31	23,283	$57.36	—	$5,700,004,373
November 1 - 30	29,642	$53.31	—	$5,700,004,373
December 1 - 31	170,193	$40.72	—	$5,700,004,373
Total	223,118	$44.13	—	

(a) All of the 223,118 shares purchased during the three-month period ended December 31, 2014 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 stock.

(b) Our Board of Directors has authorized a plan to repurchase our common stock from time to time. During the fourth quarter of 2014, we did not repurchase shares of our common stock pursuant to that plan. We have authorization remaining to repurchase up to a total of approximately $5.7 billion of our common stock.

Item 6. Selected Financial Data.

Information related to selected financial data is included on page 74 of this annual report.

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

Information related to Management's Discussion and Analysis of Financial Condition and Results of Operations is included on pages 21 through 39 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 38 of this annual report and Note 14 to the consolidated financial statements on page 68 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, 2014 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, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

See page 40 for Management’s Report on Internal Control Over Financial Reporting and page 42 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

Pending acquisition of Baker Hughes
On November 16, 2014, we and Baker Hughes entered into a merger agreement under which, subject to the conditions set forth in the merger agreement, we will acquire all the outstanding shares of Baker Hughes in a stock and cash transaction. The acquisition is expected to create a leading global oilfield services company and combine the companies' product and service capabilities to deliver exceptional depth and breadth of solutions to our customers. The closing of the transaction is expected to occur in the second half of 2015. See Note 2 to the consolidated financial statements for further information about the pending acquisition.
Financial results
During 2014, we produced revenue of $32.9 billion, an increase of $3.5 billion, or 12%, from 2013, mainly due to increased stimulation activity in the United States land market and strong growth across the Eastern Hemisphere. Our 2014 revenue in North America comprised 54% of consolidated revenue compared to 46% outside of North America. We set new revenue records this year as a total company in both divisions and in 12 out of 13 product service lines. Operating income of $5.1 billion in 2014, which reflects an operating margin of 16%, was also a total company record and was driven by stimulation activity in the United States land market and improved results in our Middle East/Asia region. As a result of the market decline discussed in further detail below, we incurred $129 million, pre-tax, of restructuring charges in the fourth quarter of 2014, consisting of severance-related costs and asset write-offs. Most of these adjustments related to our Eastern Hemisphere business.
Business outlook
While 2014 was a strong year for our company, the outlook for 2015 is uncertain due to the depressed crude oil pricing environment. We anticipate 2015 will be a challenging year for us, as our customers continue to make downward revisions to their operating budgets. Therefore, we expect a significant drop-off in activity coupled with pricing pressures, and corresponding reductions in revenue and operating margins in 2015. We continue to believe in the strength of the long-term fundamentals of our business. Despite the expected worldwide activity declines in 2015, energy demand is still expected to increase over the long term.
In 2014, North America experienced revenue growth of 16% and operating income growth of 24%, compared to 2013. However, as current market conditions begin to take effect in early 2015, with a corresponding drop in the United States rig count, we expect a decline in activity and additional pricing pressure for the North America land market. Our customers' capital expenditure budgets for 2015 are uncertain, as they adjust their spending in response to a recent significant drop in commodity prices. While the intensity and duration of the current market downturn is uncertain, we intend to remain focused on our key strategies and have taken strategic steps to reduce our underlying cost profile. We have already taken initial steps to address headcount internationally in late 2014, and are in the midst of making further headcount reductions company-wide as we evaluate market conditions. As a result, we anticipate recording further material restructuring charges, including severance costs, in 2015.
In 2014, Eastern Hemisphere revenue and operating income increased 10% and 8%, respectively, compared to 2013. However, internationally, we began to see the impact of lower commodity prices in the fourth quarter of 2014. Declining crude oil prices have caused our customers to reduce their budgets and defer several of their new projects. We expect 2015 to be a challenging year across all of our international regions, as our customers continue to respond to current market conditions.
Although the outlook for 2015 remains uncertain, we will make necessary adjustments as activity dictates. Our intention is to look beyond the down cycle and continue to execute our strategic initiatives. We plan to continue executing the following strategies in 2015:

- directing capital and resources into strategic growth markets, including unconventional plays, mature fields, and deepwater;
-

- leveraging our broad technology offerings to provide value to our customers through integrated solutions and enabling them to more efficiently drill and complete their wells;
- exploring additional opportunities for acquisitions that will enhance or augment our current portfolio of services and products, including those with unique technologies or distribution networks in areas where we do not already have significant operations;
- investing in technology that will help our customers reduce reservoir uncertainty and increase operational efficiency;
- improving working capital, and managing our balance sheet to maximize our financial flexibility; and
- continuing to seek ways to be one of the most cost efficient service providers in the industry by maintaining capital discipline and leveraging our scale and breadth of operations.

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

Financial markets, liquidity, and capital resources
We believe we have invested our cash balances conservatively and secured sufficient financing to help mitigate any near-term negative impact on our operations from adverse market conditions. We intend to finance the cash portion of the consideration payable in the acquisition of Baker Hughes through a combination of cash on hand and debt, for which we have obtained financing commitments. For additional information on market conditions and the pending acquisition of Baker Hughes, see “Liquidity and Capital Resources,” “Business Environment and Results of Operations,” and Note 2 to the consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

We ended 2014 with cash and equivalents of $2.3 billion compared to $2.4 billion at December 31, 2013. Additionally, at December 31, 2014, we held $103 million of investments in fixed income securities compared to $373 million at December 31, 2013. These securities are reflected in "Other current assets" and "Other assets" in our consolidated balance sheets. As of December 31, 2014, approximately $634 million of the $2.3 billion of cash and equivalents was held by our foreign subsidiaries, of which $181 million would be subject to United States tax if repatriated. However, our intent is to permanently reinvest these funds outside of the United States and our current plans do not suggest a need to repatriate them to fund our United States operations.

Significant sources and uses of cash

Cash flows from operating activities were $4.1 billion in 2014.

Capital expenditures were $3.3 billion in 2014. The capital expenditures in 2014 were predominantly made in our Production Enhancement, Sperry Drilling, Wireline and Perforating, Cementing, and Boots & Coots product service lines.

Our primary components of net working capital (receivables, inventories, and accounts payable) increased during the year by a net $1.1 billion, primarily due to increased business activity.

During 2014, we repurchased approximately 13.3 million shares of our common stock under our share repurchase program at a total cost of approximately $800 million.

We paid $533 million of dividends to our shareholders in 2014.

During 2014, we made our first installment payment of $395 million related to the settlement we reached during the year for the Macondo well incident. See Note 9 to the consolidated financial statements for further information.

We sold $338 million of property, plant, and equipment during 2014.

During 2014, we sold $261 million of investment securities, net of investment securities purchased.

We paid $231 million for acquisitions of various businesses during 2014, net of cash acquired, to further enhance our existing product service lines.

Future sources and uses of cash

Subject to receipt of all required approvals, the closing of the acquisition of Baker Hughes is expected to occur in the second half of 2015. We intend to finance the cash portion of the acquisition through a combination of cash on hand and debt financing. We have obtained a commitment letter for an $8.6 billion senior unsecured bridge facility, which is greater than the expected cash consideration required upon closing of the Baker Hughes acquisition. We have not drawn any amounts under this commitment as of December 31, 2014. We may issue debt securities, obtain bank loans or other debt financings, or use cash on hand in lieu of utilizing all or a portion of the bridge facility. See Note 2 to the consolidated financial statements for further information about the pending acquisition.

During 2014, we reached an agreement, subject to court approval, to settle a substantial portion of the plaintiffs' claims asserted against us relating to the Macondo well incident for approximately $1.1 billion, of which $805 million remains payable as of December 31, 2014, with $367 million expected to be paid during 2015. See Note 9 to the consolidated financial statements for further information.

During 2014, we reached a settlement with KBR, Inc. (KBR) under which KBR agreed to pay us $81 million related to amounts owed to us under our Tax Sharing Agreement with KBR. We received $25 million during the fourth quarter of 2014, and $56 million remains recorded as a receivable as of December 31, 2014, most of which we expect to receive during 2015. See Note 8 to the consolidated financial statements for further information.

Capital spending for 2015 is currently expected to be essentially in line with 2014. Although the oil and natural gas markets have weakened dramatically in recent months, our objective is to look beyond the downward cycle and continue to invest in certain strategic technologies. The capital expenditures plan for 2015 is primarily directed towards our Production Enhancement, Sperry Drilling, Boots & Coots, Cementing, and Wireline and Perforating product service lines.

Subject to Board of Directors approval, our intention is to pay dividends representing at least 15% to 20% of our net income on an annual basis. In October 2014, Halliburton’s Board of Directors approved a 20% increase of the quarterly dividend from $0.15 to $0.18 per share, or approximately $153 million per quarter.

In July 2014, our Board of Directors increased the authorization to repurchase our common stock by approximately $4.8 billion. Approximately $5.7 billion remains authorized for repurchases as of December 31, 2014, which may be used for open market and other share purchases.

We had $314 million of gross unrecognized tax benefits at December 31, 2014, of which we estimate $168 million may require a cash payment. We estimate that $162 million of the cash payment 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.

Contractual obligations

The following table summarizes our significant contractual obligations and other long-term liabilities as of December 31, 2014:

	Payments Due						
Millions of dollars	2015	2016	2017	2018	2019	Thereafter	Total
Long-term debt	$ 14	$ 610	$ 52	$ 806	$ 1,000	$ 5,389	$ 7,871
Interest on debt (a)	362	369	371	376	351	6,048	7,877
Operating leases	283	201	115	79	54	237	969
Purchase obligations (b)	1,100	429	289	118	29	68	2,033
Other long-term liabilities (c)	41	3	3	2	2	3	54
Total	$ 1,800	$ 1,612	$ 830	$ 1,381	$ 1,436	$ 11,745	$ 18,804

(a) Interest on debt includes 82 years of interest on $300 million of debentures at 7.6% interest that become due in 2096.

(b) Amount in 2015 primarily represents certain purchase orders for goods and services utilized in the ordinary course of our business.

(c) Includes capital lease obligations and pension funding obligations. Amounts for pension funding obligations, which include international plans and are based on assumptions that are subject to change, are only included for 2015 as we are currently not able to reasonably estimate our contributions for years after 2015.

Other factors affecting liquidity

Financial position in current market. As of December 31, 2014, we had $2.3 billion of cash and equivalents, $103 million in fixed income investments, and a total of $3.0 billion of available committed bank credit under our revolving credit facility. Furthermore, we have no financial covenants or material adverse change provisions in our bank agreements, and our debt maturities extend over a long period of time. Although a portion of earnings from our foreign subsidiaries is reinvested outside the United States indefinitely, we do not consider this to have a significant impact on our liquidity. We currently believe that capital expenditures, working capital investments, and dividends, if any, during 2015 can be fully funded through cash from operations.

As a result, we believe we have a reasonable amount of liquidity and, if necessary, additional financing flexibility given the current market environment to fund our potential contingent liabilities, if any. However, as discussed in Note 9 to the consolidated financial statements, there are future developments that may arise as a result of the Macondo well incident that could have a material adverse effect on our liquidity.

Guarantee agreements. In the normal course of business, we have agreements with financial institutions under which approximately $2.4 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2014. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization.

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. While these credit ratings remained unchanged during 2014, after the announcement of the pending Baker Hughes acquisition, Standard & Poor’s placed all of our ratings on negative watch.

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 as well as unsettled political conditions. If our customers delay 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. See “Business Environment and Results of Operations – International operations – Venezuela” for further discussion related to Venezuela.

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BUSINESS ENVIRONMENT AND RESULTS OF OPERATIONS

We operate in approximately 80 countries throughout the world to provide a comprehensive range of services and products to the upstream oil and natural gas industry. A significant amount of our consolidated revenue is derived from the sale of services and products to major, national, and independent oil and natural gas companies worldwide. The industry we serve is highly competitive with many substantial competitors in each segment of our business. In 2014, 2013, and 2012, based on the location of services provided and products sold, 51%, 49%, and 53% 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, sanctions, expropriation or other governmental actions, inflation, foreign currency exchange restrictions, and highly inflationary currencies, as well as other geopolitical factors. We believe the geographic diversification of our business activities reduces the risk that loss of operations in any one country, other than the United States, would be materially adverse to our consolidated results of operations.

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

Some of the more significant determinants of current and future spending levels of our customers are oil and natural gas prices, global oil supply, the world economy, the availability of credit, government regulation, 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. Additionally, due to improved drilling and completion efficiencies as more of our customers move to multi-well pad drilling, our financial performance is impacted by well count in the North America market.

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

	2014	2013	2012
Oil price - WTI (1)	$93.37	$97.99	$94.15
Oil price - Brent (1)	99.04	108.71	111.60
Natural gas price - Henry Hub (2)	4.39	3.73	2.81

(1) Oil price measured in dollars per barrel

(2) Natural gas price measured in dollars per million British thermal units (Btu), or MMBtu

	Three Months Ended December 31, 2014	Month Ended December 31, 2014
Oil price - WTI	$73.55	$59.95
Oil price - Brent	76.81	63.07

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

Land vs. Offshore	2014	2013	2012
United States:			
Land	1,804	1,705	1,872
Offshore (incl. Gulf of Mexico)	57	56	47
Total	1,861	1,761	1,919
Canada:			
Land	378	352	363
Offshore	2	2	1
Total	380	354	364
International (excluding Canada):			
Land	1,011	978	931
Offshore	326	318	303
Total	1,337	1,296	1,234
Worldwide total	3,578	3,411	3,517
Land total	3,193	3,035	3,166
Offshore total	385	376	351

Oil vs. Natural Gas	2014	2013	2012
United States (incl. Gulf of Mexico):			
Oil	1,528	1,375	1,359
Natural gas	333	386	560
Total	1,861	1,761	1,919
Canada:			
Oil	218	234	261
Natural gas	162	120	103
Total	380	354	364
International (excluding Canada):			
Oil	1,070	1,029	984
Natural gas	267	267	250
Total	1,337	1,296	1,234
Worldwide total	3,578	3,411	3,517
Oil total	2,816	2,638	2,604
Natural gas total	762	773	913

Drilling Type	2014	2013	2012
United States (incl. Gulf of Mexico):			
Horizontal	1,274	1,102	1,151
Vertical	376	435	552
Directional	211	224	216
Total	1,861	1,761	1,919

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, while the opposite is true for higher oil and natural gas prices.

WTI oil spot prices declined significantly in the second half of 2014, ranging from a high of $108 per barrel in June to a low of $53 per barrel in December, while Brent crude oil spot prices declined from a high of $115 per barrel in June to a low of $55 per barrel in December. Spot crude oil prices were negatively affected by a combination of factors, including weakening demand in Europe and Asia, and increased production in the United States. Additionally, stronger economic performance in the United States has led to a strengthening in the U.S. dollar relative to most other currencies, contributing further to the fall in the U.S dollar value of oil. In addition, the monthly average for Brent crude oil spot prices in December 2014 was $63 per barrel, down $16 per barrel from the November 2014 average, following the decision in late November by the Organization of Petroleum Exporting Countries to keep production levels unchanged.

Demand in the fourth quarter of 2014 for Europe fell by 4% from the prior quarter as curtailments in France and Germany continued to contribute to a particularly uncertain forecasting environment. Crude oil production in the United States averaged an estimated 9.2 million barrels per day in December 2014, an increase of 6% from the September 2014 average. The expansion of export possibilities in the United States contributed to the decreased differential between WTI and Brent crude oil spot prices, which has narrowed from an average of $4 per barrel in the third quarter of 2014 to $3 per barrel in the fourth quarter of 2014.

According to the United States Energy Information Administration (EIA) February 2015 "Short Term Energy Outlook," the EIA projects that Brent prices will average $58 per barrel in 2015, with increases towards the end of the year to an average of $67 per barrel during the fourth quarter. The EIA also noted that price projections reflect a scenario in which supply is expected to continue to exceed demand, leading to inventory surplus through the first three quarters of 2015. Although there are no signs that point to an immediate rebalance of the market, the International Energy Agency's (IEA) February 2015 "Oil Market Report" forecasts the 2015 global demand to average approximately 93.4 million barrels per day, which is up 1% from 2014, driven by an increase in all regions except for Europe and the Commonwealth of Independent States.

The average 2014 full year Henry Hub natural gas price in the United States increased approximately 18% from 2013 as a result of an increase in natural gas storage withdrawals related to an unseasonably harsh winter in the early part of 2014. However, natural gas spot prices declined sharply in December 2014 to a year-low $2.74 per MMBtu as a result of a warmer than normal month, along with robust production that contributed to lower than average storage withdrawals. The EIA February 2015 “Short Term Energy Outlook” projects Henry Hub natural gas prices to average $3.05 per MMBtu in 2015 compared to $4.39 per MMBtu in 2014. Over the long term, the EIA expects natural gas consumption in the power sector to increase as new industrial projects come online, offsetting the decline in residential and commercial consumption.

We believe that, over the long-term, hydrocarbon demand will generally increase, and this, combined with 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 and products.

North America operations

Volatility in oil and natural gas prices can impact our customers’ drilling and production activities. During 2014, the average full year natural gas-directed rig count in North America was flat, while the average full year oil directed rig count increased 137 rigs, or 9%, from 2013. In the United States land market, there was a modest full year increase in rig count from 2013 levels, driven primarily by the continued shift to horizontal rigs in the Permian Basin. The North America rig count and activity levels held up through most of the fourth quarter as customers executed against the remainder of their 2014 budgets.

However, the United States land rig count has fallen sharply into early 2015, and we expect activity declines for the United States land market to accelerate further in the first quarter of 2015, impacting all of the key liquid basins. Current market conditions aside, in the long run, we believe the shift to unconventional oil and liquids-rich basins in the United States land market will continue to drive increased service intensity and will require higher demand in fluid chemistry and other technologies required for these complex reservoirs which will have beneficial implications for our operations.

In the Gulf of Mexico, the average full year offshore rig count was relatively flat in 2014 as compared to 2013. Growth in the Gulf of Mexico is dependent on, among other things, governmental approvals for permits, our

customers' actions, and new deepwater rigs entering the market.
International operations
The average international rig count for 2014 modestly increased from 2013, however the total international rig count in December 2014 was down 1% from the prior month. Declining crude oil prices have caused several of our customers to reduce their budgets and defer several new projects. We expect that 2015 will be a challenging year for all of our international regions, primarily in our Europe/Africa/CIS region, with our Middle East/Asia region likely being the most resilient.
Despite the current market environment, we believe that international unconventional oil and natural gas, mature field, and deepwater projects will contribute to activity improvements over the long term, and we plan to leverage our extensive experience in North America to optimize these opportunities. Consistent with our long-term strategy to grow our operations outside of North America, we also expect to continue to invest in capital equipment for our international operations.
Venezuela. As of December 31, 2014, our total net investment in Venezuela was approximately $649 million, including net monetary assets of $162 million denominated in Bolívares. Also, at December 31, 2014 we had $276 million of surety bond guarantees outstanding relating to our Venezuelan operations. Our net investment and surety bond guarantees relating to our Venezuelan operations have increased since December 31, 2013 by 58% and 44%, respectively, corresponding to increased demand for our services in the country.

While we are continuing to collect some of our receivables from our primary customer in Venezuela, the amount of outstanding receivables has increased in connection with increased activity. These receivables are not disputed, and we have not historically had material write-offs relating to this customer. Additionally, we routinely monitor the financial stability of our customers. Our total outstanding trade receivables in Venezuela were $670 million, or approximately 9% of our gross trade receivables, as of December 31, 2014, compared to $486 million, or approximately 8% of our gross trade receivables, as of December 31, 2013. Of the $670 million of receivables in Venezuela as of December 31, 2014, $256 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets. Of the $486 million receivables in Venezuela as of December 31, 2013, $183 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets.

In February 2013, the Venezuelan government devalued the Bolívar, from the preexisting exchange rate of 4.3 Bolívares per United States dollar to 6.3 Bolívares per United States dollar, resulting in us incurring a foreign currency loss.

During 2014, the Venezuelan government made available two new foreign exchange rate mechanisms through which a company may be able to legally convert Bolívares to United States dollars, in addition to the National Center of Foreign Commerce official rate of 6.3 Bolívares per United States dollar: (i) a bid rate established via weekly auctions under the Complementary System of Foreign Currency Acquirement (SICAD I); and (ii) an auction rate which is intended to more closely resemble a market-driven exchange rate (SICAD II).

In February 2015, the Venezuelan government created a new foreign exchange rate mechanism, called the Marginal Currency System. The new mechanism, which is the third system in a three-tier exchange control mechanism, will be driven by the free market and allow for a company to legally convert Bolívares to United States dollars based on supply and demand. The three-tier exchange rate mechanisms are as follows: (i) the official rate of 6.3 discussed above, which remains unchanged; (ii) the SICAD I, which will continue to hold periodic auctions for specific sectors of the economy and begin with a rate of 12 Bolívares per United States dollar; and (iii) the Marginal Currency System, which replaces the SICAD II system and held its initial transaction at approximately 170 Bolívares per United States dollar.

The availability of alternative currency mechanisms had no impact on our results of operations during the year ended December 31, 2014 as we continue to use the official exchange rate to remeasure net assets denominated in Bolívares. We are currently evaluating the newly created Marginal Currency System and expect to utilize this rate starting in the first quarter of 2015. Had we used the Marginal Currency System potential rate of 170 Bolívares per United States dollar to remeasure our net monetary position as of December 31, 2014, we would have incurred a foreign currency loss of $156 million in 2014.

For additional information, see Part I, Item 1(a), “Risk Factors” in this Form 10-K.

RESULTS OF OPERATIONS IN 2014 COMPARED TO 2013

REVENUE: Millions of dollars	2014	2013	Favorable (Unfavorable)	Percentage Change
Completion and Production	$ 20,253	$ 17,506	$ 2,747	16 %
Drilling and Evaluation	12,617	11,896	721	6
Total revenue	$ 32,870	$ 29,402	$ 3,468	12 %
By geographic region:				
Completion and Production:				
North America	$ 13,688	$ 11,417	$ 2,271	20 %
Latin America	1,633	1,586	47	3
Europe/Africa/CIS	2,595	2,391	204	9
Middle East/Asia	2,337	2,112	225	11
Total	20,253	17,506	2,747	16
Drilling and Evaluation:				
North America	4,010	3,795	215	6
Latin America	2,242	2,323	(81)	(3)
Europe/Africa/CIS	2,895	2,834	61	2
Middle East/Asia	3,470	2,944	526	18
Total	12,617	11,896	721	6
Total revenue by region:				
North America	17,698	15,212	2,486	16
Latin America	3,875	3,909	(34)	(1)
Europe/Africa/CIS	5,490	5,225	265	5
Middle East/Asia	5,807	5,056	751	15

OPERATING INCOME: Millions of dollars	2014	2013	Favorable (Unfavorable)	Percentage Change
Completion and Production	$3,610	$2,875	$735	26 %
Drilling and Evaluation	1,671	1,770	(99)	(6)
Corporate and other	(184)	(1,507)	1,323	(88)
Total operating income	$5,097	$3,138	$1,959	62 %
By geographic region:				
Completion and Production:				
North America	$2,598	$1,916	$682	36 %
Latin America	211	211	—	—
Europe/Africa/CIS	371	356	15	4
Middle East/Asia	430	392	38	10
Total	3,610	2,875	735	26
Drilling and Evaluation:				
North America	588	656	(68)	(10)
Latin America	211	307	(96)	(31)
Europe/Africa/CIS	259	334	(75)	(22)
Middle East/Asia	613	473	140	30
Total	1,671	1,770	(99)	(6)
Total operating income by region (excluding Corporate and other):				
North America	3,186	2,572	614	24
Latin America	422	518	(96)	(19)
Europe/Africa/CIS	630	690	(60)	(9)
Middle East/Asia	1,043	865	178	21

Consolidated revenue in 2014 increased 12% compared to 2013, primarily as a result of higher stimulation activity in the United States land market and increased activity in almost all of our product service lines in the Eastern Hemisphere, which were partially offset by lower activity in Latin America. Revenue outside of North America was 46% of consolidated revenue in 2014 and 48% of consolidated revenue in 2013.

The $2.0 billion increase in consolidated operating income compared to 2013 was primarily a result of various corporate expense items in 2013 as well as increased stimulation activity in the United States land market and growth in Middle East/Asia in 2014, which more than offset lower activity and margins experienced in Latin America. Operating income in 2014 was positively impacted by $195 million of Macondo-related items as a result of a reduction of our loss contingency liability and an expected insurance recovery, offset by $129 million of restructuring charges related to severance and asset write-offs and $17 million of Baker Hughes acquisition-related costs. Operating income in 2013 was negatively impacted by the following pre-tax items: a $1.0 billion increase in our loss contingency liability related to Macondo, $92 million of restructuring charges related to severance and asset write-offs, and a $55 million charge related to a charitable contribution to the National Fish and Wildlife Foundation, partially offset by a $28 million value-added tax refund receivable in Brazil.

Completion and Production revenue increased 16% compared to 2013, with activity increases across all regions and predominately in North America. North America revenue rose 20% primarily as a result of increased stimulation activity in the United States land market. Latin America revenue improved 3%, as increased activity levels in the majority of our product service lines in Venezuela and Argentina more than offset a decrease in stimulation activity in Mexico and lower pressure pumping activity in Brazil. Europe/Africa/CIS revenue grew 9%, driven by strong growth across most of our product service lines in Angola and the United Kingdom, as well as increased completion tools sales in Nigeria, which were partially offset by lower pressure pumping activity and currency weakness in Norway. Middle East/Asia revenue improved 11% primarily due to increased activity in the majority of our product service lines in Saudi Arabia, higher cementing activity in Thailand, and increased stimulation and artificial lift activity in Australia, which more than offset reduced activity levels in Oman and a decline in completion tools sales in Malaysia. Revenue outside of North America was 32% of total segment revenue in 2014 and 35% of total segment revenue in 2013.

Completion and Production operating income increased 26% compared to 2013, driven predominantly by strong growth in North America coupled with modest improvement in the Eastern Hemisphere. North America operating income rose 36% from 2013, primarily due to increased profitability for stimulation activity in the United States land market. Latin America operating income was flat as improved pressure pumping activity in Argentina and increased profitability for well intervention services in Mexico and Venezuela were offset by reduced completion tools sales and profitability in Brazil, Mexico and Trinidad. Europe/Africa/CIS operating income grew 4% compared to 2013, primarily due to higher completion products sales in Nigeria, Angola and the United Kingdom, which were partially offset by decreased well completion activity and currency weakness in Russia and Norway. Middle East/Asia operating income rose by 10% primarily due to increased profitability for the majority of our product services lines in Saudi Arabia, which was partially offset by reduced activity levels in China and Oman.

Drilling and Evaluation revenue increased 6% compared to 2013, primarily due to a strong performance in the Eastern Hemisphere, primarily in Saudi Arabia, which was partially offset by a decrease in drilling activity and consulting services in Latin America. North America revenue rose by 6% due to increased fluids activity in the United States land market and higher activity in the majority of our product service lines in the Gulf of Mexico. Latin America revenue decreased 3%, as reduced activity across all of our product service lines in Mexico and a decline in drilling activity in Brazil more than offset increased activity across all of our product service lines in Venezuela and Argentina. Europe/Africa/CIS revenue was relatively flat as increased testing activity in Angola and Nigeria was offset by decreased drilling and fluids activity in Egypt and Libya. Middle East/Asia revenue rose 18% as a result of increased activity in all of our product services lines in Saudi Arabia and increased demand for drilling services in Thailand and fluids activity in Australia, India and Iraq. Revenue outside of North America was 68% of total segment revenue in both 2014 and 2013.

Drilling and Evaluation operating income decreased 6% compared to 2013, primarily due to lower drilling activity and margins in Latin America and lower profitability in the Europe/Africa/CIS region. This decrease was partially offset by strong activity growth in the Middle East/Asia region. North America operating income was down 10% from 2013 due to a decline in drilling services in Canada and the United States land market. Latin America operating income declined 31% mainly due to reduced activity levels in Mexico and lower drilling activity and pricing in Brazil, which were partially offset by improved activity levels in Argentina. The Europe/Africa/CIS region operating income fell 22% primarily due to lower activity and currency weakness in Russia and Norway. Middle East/Asia operating income increased 30% primarily due to an increase in demand and profitability for drilling activity in Saudi Arabia, as well as improved demand for drilling services in Thailand, which were partially offset by reduced drilling services and logging activity in China.

Corporate and other expenses were $184 million in 2014 compared to $1.5 billion in 2013. The significant decrease was primarily due to Macondo-related items. In 2013, we recorded a $1.0 billion increase to our loss contingency for the Macondo well incident, while in 2014 we recorded a reduction of our loss contingency liability and an expected insurance recovery totaling $195 million. We recorded $17 million of costs in 2014 related to the pending Baker Hughes acquisition and a $55 million charge in 2013 related to a charitable contribution to the National Fish and Wildlife Foundation. See Note 9 to the consolidated financial statements for further information regarding the Macondo well incident.

NONOPERATING ITEMS

Interest expense, net increased $52 million in 2014, compared to 2013, primarily due to higher interest expense as a result of the issuance of $3.0 billion aggregate principal amount of senior notes in August 2013.

Effective tax rate. Our effective tax rate was 27.1% for 2014 and 23.5% for 2013. The effective tax rate for 2014 was positively impacted by a $201 million net operating loss valuation allowance released as a result of a reorganization of our legal entity structure in Brazil, as well as lower tax rates in certain foreign jurisdictions. Partially offsetting these items were tax expenses related to Macondo items recorded during 2014, which was tax-effected at the United States statutory rate, as well as total charges of approximately $150 million for a write-off of certain prepaid tax assets recorded in Iraq, additional tax expenses related to the settlement of a research and development credit with the United States tax authorities, and tax expenses related to other unrecognized tax benefits. Our effective tax rate for 2013 was also positively impacted by lower tax rates in certain foreign jurisdictions; federal tax benefits of approximately $50 million due to the reinstatement of certain tax benefits and credits related to the first quarter of 2013 enactment of the American Taxpayer Relief Act of 2012; and the tax impact related to an increase of our Macondo-related loss contingency recorded during 2013, which was tax-effected at the United States statutory rate. See Note 10 to the consolidated financial statements for further information regarding income taxes.

Income from discontinued operations, net was $64 million in 2014, compared to $19 million in 2013, primarily due to $63 million of income recorded in 2014 related to a settlement we reached with KBR for amounts owed to us under our Tax Sharing Agreement with KBR. See Note 8 to the consolidated financial statements for further information.

RESULTS OF OPERATIONS IN 2013 COMPARED TO 2012

REVENUE: Millions of dollars	2013	2012	Favorable (Unfavorable)	Percentage Change
Completion and Production	$17,506	$17,380	$126	1 %
Drilling and Evaluation	11,896	11,123	773	7
Total revenue	$29,402	$28,503	$899	3 %
By geographic region:				
Completion and Production:				
North America	$11,417	$12,157	$(740)	(6)%
Latin America	1,586	1,415	171	12
Europe/Africa/CIS	2,391	2,099	292	14
Middle East/Asia	2,112	1,709	403	24
Total	17,506	17,380	126	1
Drilling and Evaluation:				
North America	3,795	3,847	(52)	(1)
Latin America	2,323	2,279	44	2
Europe/Africa/CIS	2,834	2,411	423	18
Middle East/Asia	2,944	2,586	358	14
Total	11,896	11,123	773	7
Total revenue by region:				
North America	15,212	16,004	(792)	(5)
Latin America	3,909	3,694	215	6
Europe/Africa/CIS	5,225	4,510	715	16
Middle East/Asia	5,056	4,295	761	18

OPERATING INCOME:			Favorable	Percentage
Millions of dollars	2013	2012	(Unfavorable)	Change
Completion and Production	$2,875	$3,144	$(269)	(9)%
Drilling and Evaluation	1,770	1,675	95	6
Corporate and other	(1,507)	(660)	(847)	128
Total operating income	$3,138	$4,159	$(1,021)	(25)%
By geographic region:				
Completion and Production:				
North America	$1,916	$2,260	$(344)	(15)%
Latin America	211	206	5	2
Europe/Africa/CIS	356	347	9	3
Middle East/Asia	392	331	61	18
Total	2,875	3,144	(269)	(9)
Drilling and Evaluation:				
North America	656	680	(24)	(4)
Latin America	307	393	(86)	(22)
Europe/Africa/CIS	334	246	88	36
Middle East/Asia	473	356	117	33
Total	1,770	1,675	95	6
Total operating income by region (excluding Corporate and other):				
North America	2,572	2,940	(368)	(13)
Latin America	518	599	(81)	(14)
Europe/Africa/CIS	690	593	97	16
Middle East/Asia	865	687	178	26

Consolidated revenue in 2013 increased 3% compared to 2012, primarily driven by activity growth across all international regions. This was partially offset by lower activity levels and pricing pressure in the United States land market. Revenue outside of North America was 48% of consolidated revenue in 2013 and 44% of consolidated revenue in 2012.

The $1.0 billion decrease in consolidated operating income compared to 2012 was primarily related to Macondo-related charges. Operating income in 2013 was impacted by the following pre-tax items: a $1.0 billion Macondo-related loss contingency, $92 million of restructuring charges related to severance and asset write-offs, and a $55 million charge related to a charitable contribution to the National Fish and Wildlife Foundation, partially offset by a $28 million value-added tax refund receivable in Brazil. Operating income in 2012 was impacted by the following pre-tax items: a $300 million Macondo-related loss contingency, along with a $48 million charge related to an earn-out adjustment due to significantly better than expected performance of a past acquisition, partially offset by a $20 million gain related to the settlement of a patent infringement lawsuit.

Completion and Production revenue increased slightly compared to 2012 due to strong international growth, which was partially offset by a decline in North America activity. North America revenue decreased 6%, primarily due to pricing pressures in the United States hydraulic fracturing market and lower activity in Canada. Latin America revenue was up 12% due to increased completion products sales in Brazil and higher activity in most product service lines in Mexico and Argentina. Europe/Africa/CIS revenue grew 14%, driven by strong demand for cementing services in Norway, West Africa, and Russia and completion tools throughout the region. Middle East/Asia revenue improved 24% due to higher activity in most product service lines in Saudi Arabia, Australia, Indonesia, and China, increased completion tools sales in Malaysia, and higher demand for cementing services in Thailand. Revenue outside of North America was 35% of total segment revenue in 2013 and 30% of total segment revenue in 2012.

Completion and Production operating income decreased 9% compared to 2012, primarily due to the North America region, where operating income fell 15% due to pricing pressures in the United States hydraulic fracturing market and lower activity in Canada. Latin America operating income was up 2% as a result of higher demand for cementing services in Mexico and Venezuela and production enhancement services in Argentina. Europe/Africa/CIS operating income grew 3% compared to 2012, driven by higher completion products activity in Angola and cementing activity in Norway. Middle East/Asia operating income increased 18% due to higher activity levels in Saudi Arabia and Iraq, higher direct sales in China, and improved profitability in Indonesia.

Drilling and Evaluation revenue increased 7% compared to 2012, driven by strong results in the Eastern Hemisphere. North America revenue was essentially flat, as lower demand for drilling and wireline services was partially offset by fluids activity across the United States land market and higher activity in the Gulf of Mexico. Latin America revenue was also relatively flat, as higher demand for all product lines in Mexico and fluids throughout the region were partially offset by lower drilling services activity in Colombia and wireline activity in Brazil. Europe/Africa/CIS revenue increased 18% due to improved fluids activity in Norway and Angola and higher drilling services activity in Eurasia, Norway, Egypt, and Angola. Middle East/Asia revenue rose 14% primarily due to strong demand in Saudi Arabia and Indonesia, higher drilling activity throughout the region, and higher wireline activity in Asia Pacific. Revenue outside of North America was 68% of total segment revenue in 2013 and 65% of total segment revenue in 2012.

Drilling and Evaluation operating income improved 6% compared to 2012, as increased activity in the Eastern Hemisphere was partially offset by higher costs in Latin America. North America operating income was down 4% from 2012, as a reduction in drilling and wireline services was partially offset by demand for fluids and consulting and project management. Latin America operating income declined 22% due to higher costs in Brazil and Venezuela and lower activity in Colombia. The Europe/Africa/CIS region operating income grew 36%, driven by fluids activity in Angola and Norway and drilling services in Eurasia. Middle East/Asia operating income increased 33% as a result of higher activity in Iraq, Indonesia, and Malaysia.

Corporate and other expenses were $1.5 billion in 2013 compared to $660 million in 2012. The significant increase was primarily due to a $1.0 billion Macondo-related loss contingency that was recorded in the first quarter of 2013, compared to a $300 million Macondo-related loss contingency recorded in the first quarter of 2012. Additionally, a $55 million charitable contribution to the National Fish and Wildlife Foundation was expensed in the second quarter of 2013, reflecting our commitment to making a positive environmental impact in our local communities.

NONOPERATING ITEMS

Effective tax rate. Our effective tax rate on continuing operations was 23.5% for 2013 and 32.3% for 2012. The 2013 effective tax rate on continuing operations was positively impacted by several items during the year, including federal tax benefits of approximately $50 million due to the reinstatement of certain tax benefits and credits related to the first quarter enactment of the American Taxpayer Relief Act of 2012. Also contributing to the lower tax rate in 2013 was a $1.0 billion loss contingency related to the Macondo well incident, which was tax-effected at the United States statutory rate, as well as some favorable tax items in Latin America in the fourth quarter. Additionally, our effective tax rate was positively impacted by lower tax rates in certain foreign jurisdictions, as we continue to reposition our technology, supply chain, and manufacturing infrastructure to more effectively serve our customers internationally.

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 judgments 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, environmental, and investigation matters;
- valuations of long-lived assets, including intangible assets and goodwill;
- purchase price allocation for acquired businesses;
- pensions;
- allowance for bad debts; and
- percentage-of-completion accounting for long-term, integrated project management 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. 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, environmental, and investigation matters

As discussed in Note 9 of our consolidated financial statements, as of December 31, 2014, we have accrued an estimate of the probable and estimable costs for the resolution of some of our legal, environmental, 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 accuracy of these estimates is impacted by, among other things, the complexity of the issues and 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.

Value of long-lived assets, including intangible assets and goodwill

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 on 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. See Note 1 to the consolidated financial statements for our accounting policies related to long-lived assets and intangible assets, as well as the results of our goodwill impairment assessment, including our updated assessment performed as a result of the decline in crude oil prices subsequent to our goodwill impairment assessment date in 2014.

The quantitative impairment test we perform for goodwill utilizes certain assumptions, including forecasted revenue and costs assumptions. If the crude oil market continues to decline and remains at low levels for a sustained period of time, we could record an impairment of the carrying value of our goodwill in the future. If crude oil prices decline further or remain at low levels, to the extent appropriate we expect to perform our goodwill impairment assessment on a more frequent basis to determine whether an impairment is required.

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 inventories, 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. Our acquisitions may also include contingent consideration, or earn-out provisions, which provide for additional consideration to be paid to the seller if certain future conditions are met. These earn-out provisions are estimated and recognized at fair value at the acquisition date based on projected earnings or other financial metrics over specified periods after the acquisition date. These estimates are reviewed during the specified period and adjusted based on actual results.

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. These assumptions differ based on varying factors specific to each particular country or economic environment.

The discount rate utilized in 2014 to determine the projected benefit obligation at the measurement date for our United Kingdom pension plan, which constituted 80% of our international plans' pension obligations, was 3.75%, compared to a discount rate of 4.5% utilized in 2013. The expected long-term rate of return assumption used for our United Kingdom pension plan expense was 6.5% in 2014 and 2013.

The following table illustrates the sensitivity to changes in certain assumptions, holding all other assumptions constant, for our United Kingdom pension plan.

Millions of dollars	Effect on Pretax Pension Expense in 2014	Pension Benefit Obligation at December 31, 2014
50-basis-point decrease in discount rate	$ 3	$ 121
50-basis-point increase in discount rate	(3)	(105)
50-basis-point decrease in expected long-term rate of return	4	NA
50-basis-point increase in expected long-term rate of return	(4)	NA

Our international defined benefit plans reduced pretax income by $36 million in 2014, $32 million in 2013, and $26 million in 2012. Included in these amounts was income from expected return on plan assets of $52 million in 2014, $44 million in 2013, and $45 million in 2012. Actual returns on international plan assets totaled $69 million in 2014, compared to $117 million in 2013. Our net actuarial loss, net of tax, related to international pension plans was $298 million at December 31, 2014 and $222 million at December 31, 2013. In our international plans where employees earn additional benefits for continued service, actuarial gains and losses will be recognized in operating income over a period of two to 17 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 will be recognized in operating income over a period of 17 to 32 years, which represents the estimated average remaining lifetime of the benefit obligations. These ranges reflect varying maturity levels among the plans.

During 2014, we made contributions of $16 million to our international defined benefit plans. We expect to make contributions of approximately $14 million to our international defined benefit plans in 2015.

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 15 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 1.6% to 2.7%. At December 31, 2014, allowance for bad debts totaled $137 million, or 1.8% of notes and accounts receivable before the allowance. At December 31, 2013, allowance for bad debts totaled $117 million, or 1.9% of notes and accounts receivable before the allowance. A hypothetical 100 basis point change in our estimate of the collectability of our notes and accounts receivable balance as of December 31, 2014 would have resulted in a $76 million adjustment to 2014 total operating costs and expenses. See Note 4 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. 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. 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.
At least quarterly, significant projects are reviewed in detail by senior management. There are many factors that impact future costs, including weather, inflation, labor and community disruptions, timely availability of materials, productivity, and other factors as outlined in Item 1(a), "Risk Factors." These factors can affect the accuracy of our estimates and materially impact our future reported earnings. See Note 1 to the consolidated financial statements for further information.

OFF BALANCE SHEET ARRANGEMENTS

At December 31, 2014, 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 – Contractual obligations."

FINANCIAL INSTRUMENT MARKET RISK

We are exposed to market risk from changes in foreign currency exchange rates and interest rates. We selectively manage these exposures through the use of derivative instruments, including forward foreign exchange contracts, foreign exchange options, and interest rate swaps. The objective of our risk management strategy is to minimize the volatility from fluctuations in foreign currency and interest rates. We do not use derivative instruments for trading purposes. The counterparties to our forward contracts, options, and interest rate swaps are global commercial and investment banks.
We use a sensitivity analysis model to measure the impact of a 10% adverse movement of foreign currency exchange rates against the United States dollar. A hypothetical 10% adverse change in the value of all our foreign currency positions relative to the United States dollar as of December 31, 2014 would result in a $90 million, pre-tax, loss for our net monetary assets denominated in currencies other than United States dollars.
With respect to interest rates sensitivity, after consideration of the impact from the interest rate swaps, a hypothetical 100 basis point increase in the LIBOR rate would result in approximately an additional $15 million of interest charges for the year ended December 31, 2014.
There are certain limitations inherent in the sensitivity analyses presented, primarily due to the assumption that interest rates and exchange rates change instantaneously in an equally adverse fashion. In addition, the analyses are unable to reflect the complex market reactions that normally would arise from the market shifts modeled. While this is our best estimate of the impact of the various scenarios, these estimates should not be viewed as forecasts.
For further information regarding foreign currency exchange risk, interest rate risk, and credit risk, see Note 14 to the consolidated financial statements.

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 9 to the consolidated financial statements and Part I, Item 1(a), "Risk Factors."

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,” “believe,” “do not believe,” “plan,” “estimate,” “intend,” “expect,” “do not expect,” “anticipate,” “do not anticipate,” “should,” “likely,” and other expressions. We 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 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 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, 2014 based upon criteria set forth in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, we believe that, as of December 31, 2014, our internal control over financial reporting is effective.

The effectiveness of Halliburton's internal control over financial reporting as of December 31, 2014 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/ Christian A. Garcia
David J. Lesar	Christian A. Garcia
Chairman of the Board and	Senior Vice President, Finance and
Chief Executive Officer	Acting 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, 2014 and 2013, and the related consolidated statements of operations, shareholders' equity, comprehensive income, and cash flows for each of the years in the three year period ended December 31, 2014. These consolidated financial statements are the responsibility of Halliburton 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, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2014, 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, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2015 expressed an unqualified opinion on the effectiveness of Halliburton Company's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 24, 2015

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, 2014, based on criteria established in Internal Control - Integrated Framework (2013) 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 Halliburton 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, 2014, based on criteria established in Internal Control - Integrated Framework (2013) 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 and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, shareholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 24, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 24, 2015

HALLIBURTON COMPANY
Consolidated Statements of Operations

	Year Ended December 31		
Millions of dollars and shares except per share data	2014	2013	2012
Revenue:			
Services	$25,039	$22,257	$22,196
Product sales	7,831	7,145	6,307
Total revenue	32,870	29,402	28,503
Operating costs and expenses:			
Cost of services	21,060	18,959	18,447
Cost of sales	6,599	5,972	5,322
Activity related to the Macondo well incident	(195)	1,000	300
General and administrative	309	333	275
Total operating costs and expenses	27,773	26,264	24,344
Operating income	5,097	3,138	4,159
Interest expense, net of interest income of $13, $8, and $7	(383)	(331)	(298)
Other, net	(2)	(43)	(39)
Income from continuing operations before income taxes	4,712	2,764	3,822
Provision for income taxes	(1,275)	(648)	(1,235)
Income from continuing operations	3,437	2,116	2,587
Income from discontinued operations, net of income tax (provision) benefit of $(9), $1, and $82	64	19	58
Net income	$3,501	$2,135	$2,645
Noncontrolling interest in net income of subsidiaries	(1)	(10)	(10)
Net income attributable to company	$3,500	$2,125	$2,635
Amounts attributable to company shareholders:			
Income from continuing operations	$3,436	$2,106	$2,577
Income from discontinued operations, net	64	19	58
Net income attributable to company	$3,500	$2,125	$2,635
Basic income per share attributable to company shareholders:			
Income from continuing operations	$4.05	$2.35	$2.78
Income from discontinued operations, net	0.08	0.02	0.07
Net income per share	$4.13	$2.37	$2.85
Diluted income per share attributable to company shareholders:			
Income from continuing operations	$4.03	$2.33	$2.78
Income from discontinued operations, net	0.08	0.03	0.06
Net income per share	$4.11	$2.36	$2.84
Basic weighted average common shares outstanding	848	898	926
Diluted weighted average common shares outstanding	852	902	928

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Comprehensive Income

	Year Ended December 31		
Millions of dollars	2014	2013	2012
Net income	$3,501	$2,135	$2,645
Other comprehensive income, net of income taxes:			
Defined benefit and other postretirement plans adjustments	(84)	—	(33)
Other	(7)	2	(3)
Other comprehensive income (loss), net of income taxes	(91)	2	(36)
Comprehensive income	$3,410	$2,137	$2,609
Comprehensive income attributable to noncontrolling interest	(1)	(10)	(10)
Comprehensive income attributable to company shareholders	$3,409	$2,127	$2,599

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Balance Sheets

	December 31	
Millions of dollars and shares except per share data	2014	2013
Assets		
Current assets:		
Cash and equivalents	$ 2,291	$ 2,356
Receivables (net of allowances for bad debts of $137 and $117)	7,564	6,181
Inventories	3,571	3,305
Prepaid expenses	658	737
Current deferred income taxes	421	388
Other current assets	563	737
Total current assets	15,068	13,704
Property, plant, and equipment (net of accumulated depreciation of $11,007 and $9,480)	12,475	11,322
Goodwill	2,330	2,168
Other assets	2,367	2,029
Total assets	$ 32,240	$ 29,223
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 2,814	$ 2,365
Accrued employee compensation and benefits	1,033	1,029
Taxes other than income	407	357
Loss contingency for Macondo well incident	367	278
Deferred revenue	349	350
Other current liabilities	913	647
Total current liabilities	5,883	5,026
Long-term debt	7,840	7,816
Employee compensation and benefits	691	584
Loss contingency for Macondo well incident	439	1,022
Other liabilities	1,089	1,160
Total liabilities	15,942	15,608
Shareholders' equity:		
Common shares, par value $2.50 per share (authorized 2,000 shares, issued 1,071 and 1,072 shares)	2,679	2,680
Paid-in capital in excess of par value	309	415
Accumulated other comprehensive loss	(399)	(307)
Retained earnings	21,809	18,842
Treasury stock, at cost (223 shares)	(8,131)	(8,049)
Company shareholders' equity	16,267	13,581
Noncontrolling interest in consolidated subsidiaries	31	34
Total shareholders' equity	16,298	13,615
Total liabilities and shareholders' equity	$ 32,240	$ 29,223

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Cash Flows

	Year Ended December 31		
Millions of dollars	2014	2013	2012
Cash flows from operating activities:			
Net income	$3,501	$2,135	$2,645
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation, depletion, and amortization	2,126	1,900	1,628
Activity related to the Macondo well incident	(569)	1,000	300
Deferred income tax (benefit) provision, continuing operations	(454)	(132)	165
Stock-based compensation cost	298	264	217
Other changes:			
Receivables	(1,375)	(449)	(682)
Accounts payable	489	327	200
Inventories	(247)	(107)	(611)
Payment of Barracuda-Caratinga obligation	—	(219)	—
Other	293	(272)	(208)
Total cash flows from operating activities	4,062	4,447	3,654
Cash flows from investing activities:			
Capital expenditures	(3,283)	(2,934)	(3,566)
Sales of investment securities	444	356	258
Sales of property, plant, and equipment	338	241	395
Payments to acquire businesses, net of cash acquired	(231)	(94)	(214)
Purchases of investment securities	(183)	(329)	(506)
Other investing activities	(223)	(110)	(55)
Total cash flows from investing activities	(3,138)	(2,870)	(3,688)
Cash flows from financing activities:			
Payments to reacquire common stock	(800)	(4,356)	—
Proceeds from long-term borrowings, net of offering costs	—	2,968	—
Dividends to shareholders	(533)	(465)	(333)
Proceeds from exercises of stock options	332	277	107
Other financing activities	(29)	(178)	54
Total cash flows from financing activities	(1,030)	(1,754)	(172)
Effect of exchange rate changes on cash	41	49	(8)
Decrease in cash and equivalents	(65)	(128)	(214)
Cash and equivalents at beginning of year	2,356	2,484	2,698
Cash and equivalents at end of year	$2,291	$2,356	$2,484
Supplemental disclosure of cash flow information:			
Cash payments during the year for:			
Interest	$384	$293	$294
Income taxes	$1,269	$913	$1,098

See notes to consolidated financial statements.

HALLIBURTON COMPANY
Consolidated Statements of Shareholders' Equity

Millions of dollars	Company Shareholders' Equity 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, 2011	$2,683	$455	$(4,547)	$14,880	$ (273)	$ 18	$13,216
Comprehensive income (loss):							
Net income	—	—	—	2,635	—	10	2,645
Other comprehensive loss	—	—	—	—	(36)	—	(36)
Cash dividends ($0.36 per share)	—	—	—	(333)	—	—	(333)
Stock plans	(1)	25	271	—	—	—	295
Other	—	6	—	—	—	(3)	3
Balance at December 31, 2012	$2,682	$486	$(4,276)	$17,182	$ (309)	$ 25	$15,790
Comprehensive income (loss):							
Net income	—	—	—	2,125	—	10	2,135
Other comprehensive income	—	—	—	—	2	—	2
Common shares repurchased	—	—	(4,356)	—	—	—	(4,356)
Stock plans	(2)	(97)	583	—	—	—	484
Cash dividends ($0.525 per share)	—	—	—	(465)	—	—	(465)
Other	—	26	—	—	—	(1)	25
Balance at December 31, 2013	$2,680	$415	$(8,049)	$18,842	$ (307)	$ 34	$13,615
Comprehensive income (loss):							
Net income	—	—	—	3,500	—	1	3,501
Other comprehensive loss	—	—	—	—	(92)	—	(92)
Common shares repurchased	—	—	(800)	—	—	—	(800)
Stock plans	(1)	(161)	718	—	—	—	556
Cash dividends ($0.63 per share)	—	—	—	(533)	—	—	(533)
Other	—	55	—	—	—	(4)	51
Balance at December 31, 2014	$2,679	$309	$(8,131)	$21,809	$ (399)	$ 31	$16,298

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 United States generally accepted accounting principles, 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, 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 of accounting. If we do not have significant influence, we use the cost method of accounting.
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.
New Accounting Pronouncement. In May 2014, a new revenue recognition standard was issued that will supersede existing revenue recognition guidance. See Note 16 for additional information.
Research and development
Research and development costs are expensed as incurred. Research and development costs were $601 million in 2014, $588 million in 2013, and $460 million in 2012.

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 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. Changes in the carrying amount of goodwill are detailed below by reportable segment.

Millions of dollars	Completion and Production	Drilling and Evaluation	Total
Balance at December 31, 2012:	$1,511	$624	$2,135
Current year acquisitions	43	10	53
Purchase price adjustments for previous acquisitions	(21)	1	(20)
Balance at December 31, 2013:	$1,533	$635	$2,168
Current year acquisitions	77	79	156
Purchase price adjustments for previous acquisitions	(4)	10	6
Balance at December 31, 2014:	$1,606	$724	$2,330

The reported amounts of goodwill for each reporting unit are reviewed for impairment on an annual basis, during the third quarter, and more frequently should negative conditions such as significant current or projected operating losses exist. In 2012, we elected to perform a qualitative assessment for our annual goodwill impairment test. If a qualitative assessment indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, then we would be required to perform a quantitative impairment test for goodwill. In 2013 and 2014, we elected to bypass the qualitative assessment and perform a quantitative impairment test. This two-step process 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. As a result of our annual goodwill impairment assessments performed in 2014, 2013, and 2012, no impairments were deemed necessary.

Subsequent to our annual goodwill impairment testing date in 2014, the energy market experienced a considerable downturn as a result of a significant reduction in crude oil prices. Due to this pricing decline and its corresponding impact on our short-term business outlook, we determined that these recent events constituted a triggering event that would require us to update our goodwill impairment assessment through December 31, 2014. As a result of our analysis, we determined that the fair value of each reporting unit exceeded its net book value and therefore, no goodwill impairment was necessary as of December 31, 2014.

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 two to seventeen 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 and interest 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 that are not hedges are adjusted to fair value and reflected through the results of operations. If the derivative is designated as a hedge, depending on the nature of the hedge, changes in the fair value of derivatives are either offset against:

- the change in fair value of the hedged assets, liabilities, or firm commitments through earnings; or
- recognized in other comprehensive income until the hedged item is recognized in earnings.

The ineffective portion of a derivative’s change in fair value is recognized in earnings. Recognized gains or losses on derivatives entered into to manage foreign currency exchange risk are included in “Other, net” on the consolidated statements of operations. Gains or losses on interest rate derivatives are included in “Interest expense, net.”

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 12 for additional information related to stock-based compensation.

Note 2. Acquisitions and Dispositions

Pending acquisition of Baker Hughes

On November 16, 2014, we and Baker Hughes entered into a merger agreement under which, subject to the conditions set forth in the merger agreement, we will acquire all the outstanding shares of Baker Hughes in a stock and cash transaction. Baker Hughes is a leading supplier of oilfield services, products, technology and systems to the worldwide oil and natural gas industry. Under the terms of the merger agreement, at the effective time of the acquisition, each share of Baker Hughes common stock will be converted into the right to receive 1.12 shares of our common stock and $19.00 in cash.

Because the exchange ratio was fixed at the time of the merger agreement and the market value of our common stock will continue to fluctuate, the total value of the consideration exchanged will not be determinable until the closing date. The number of shares to be issued will not fluctuate based upon changes in the price of shares of our common stock or shares of Baker Hughes common stock prior to the closing date, but the exact number of Halliburton shares to be issued with respect to Baker Hughes stock awards will not be determinable until the closing of the transaction. We have estimated the total consideration expected to be issued and paid to Baker Hughes stockholders in the acquisition to consist of approximately 490 million shares of our common stock and approximately $8.3 billion to be paid in cash.

We intend to finance the cash portion of the acquisition through a combination of cash on hand and debt financing. We have obtained a commitment letter for an $8.6 billion senior unsecured bridge facility, which is greater than the expected cash consideration required upon closing of the Baker Hughes acquisition. We may issue debt securities, obtain bank loans or other debt financings, or use cash on hand in lieu of utilizing all or a portion of the bridge facility.

The merger agreement has been unanimously approved by both companies' Board of Directors. The closing of the transaction is subject to adoption of the merger agreement by the stockholders of Baker Hughes, the approval by our stockholders of the issuance of Halliburton Company common stock to Baker Hughes’s stockholders, receipt of certain regulatory approvals and other conditions specified in the merger agreement. The closing of the transaction is expected to occur in the second half of 2015.

Note 3. 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, specialty chemicals, artificial lift, and completion services. The segment consists of Production Enhancement, Cementing, Completion Tools, Boots & Coots, Multi-Chem, and Artificial Lift.

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.

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.

Completion Tools provides downhole solutions and services to our customers to complete their wells, including well completion products and services, intelligent well completions, liner hanger systems, sand control systems, and service tools.

Boots & Coots includes well intervention services, pressure control, equipment rental tools and services, and pipeline and process services.

Multi-Chem includes oilfield production and completion chemicals and services that address production, processing, and transportation challenges.

Artificial Lift offers electrical submersible pumps and progressive cavity pumps, including the associated surface package for power, control, and monitoring of the entire lift system, and provides installation, maintenance, repair, and testing services. The objective of these services is to maximize reservoir and wellbore recovery by applying lifting technology and intelligent field management solutions throughout the life of the well.

Drilling and Evaluation provides field and reservoir modeling, drilling, evaluation, and precise wellbore placement solutions that enable customers to model, measure, drill, and optimize their well construction activities. The segment consists of Baroid, Sperry Drilling, Wireline and Perforating, Drill Bits and Services, Landmark Software and Services, Testing and Subsea, and Consulting and Project Management.

Baroid 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.

Sperry Drilling 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.

Wireline and Perforating services include open-hole logging services that provide information on formation evaluation and reservoir fluid analysis, including formation lithology, rock properties, and reservoir fluid properties. Also offered are cased-hole and slickline services, which provide perforating, pipe recovery services, through-casing formation evaluation and reservoir monitoring, casing and cement integrity measurements, and well intervention services. Borehole seismic services include downhole seismic operations check-shots and vertical seismic profiles, and provide the link between surface seismic and the wellbore. Finally, formation and reservoir solutions transform formation evaluation data into reservoir insight through geoscience solutions.

Drill Bits and Services 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.

Landmark Software and Services is a supplier of integrated exploration, drilling and production software, and related professional and data management services for the upstream oil and natural gas industry.

Testing and Subsea services provide acquisition and analysis of dynamic reservoir information and reservoir optimization solutions to the oil and natural gas industry through a broad portfolio of test tools, data acquisition services, fluid sampling, surface well testing, and subsea safety systems.

Consulting and Project Management 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 and is primarily composed of cash and equivalents, deferred tax assets, and investment securities. Also included are certain gains, losses and costs not attributable to a particular business segment (such as activity related to the Macondo well incident recorded during the 2014 and 2013).

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 of accounting 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 2014	2013	2012
Revenue:			
Completion and Production	$ 20,253	$ 17,506	$ 17,380
Drilling and Evaluation	12,617	11,896	11,123
Total revenue	$ 32,870	$ 29,402	$ 28,503
Operating income:			
Completion and Production	$ 3,610	$ 2,875	$ 3,144
Drilling and Evaluation	1,671	1,770	1,675
Total operations	5,281	4,645	4,819
Corporate and other	(184)	(1,507)	(660)
Total operating income	$ 5,097	$ 3,138	$ 4,159
Interest expense, net of interest income	$ (383)	$ (331)	$ (298)
Other, net	(2)	(43)	(39)
Income from continuing operations before income taxes	$ 4,712	$ 2,764	$ 3,822
Capital expenditures:			
Completion and Production	$ 1,953	$ 1,676	$ 2,177
Drilling and Evaluation	1,297	1,210	1,318
Corporate and other	33	48	71
Total	$ 3,283	$ 2,934	$ 3,566
Depreciation, depletion, and amortization:			
Completion and Production	$ 1,162	$ 1,013	$ 843
Drilling and Evaluation	934	873	783
Corporate and other	30	14	2
Total	$ 2,126	$ 1,900	$ 1,628

Millions of dollars	December 31 2014	2013
Total assets:		
Completion and Production	$ 16,033	$ 14,203
Drilling and Evaluation	11,237	10,010
Shared assets	1,930	1,351
Corporate and other	3,040	3,659
Total	$ 32,240	$ 29,223

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 and equivalents, are considered to be shared among the segments.

The following tables present information by geographic area. In 2014, 2013, and 2012, based on the location of services provided and products sold, 51%, 49%, and 53% of our consolidated revenue was from the United States. As of December 31, 2014 and December 31, 2013, 46% and 47% of our property, plant, and equipment was from the United States. No other country accounted for more than 10% of our revenue or property, plant, and equipment during the periods presented.

Operations by geographic region

	Year Ended December 31		
Millions of dollars	2014	2013	2012
Revenue:			
North America	$17,698	$15,212	$16,004
Latin America	3,875	3,909	3,694
Europe/Africa/CIS	5,490	5,225	4,510
Middle East/Asia	5,807	5,056	4,295
Total	$32,870	$29,402	$28,503

	December 31	
Millions of dollars	2014	2013
Net property, plant, and equipment:		
North America	$6,057	$5,687
Latin America	1,406	1,227
Europe/Africa/CIS	1,832	1,639
Middle East/Asia	3,180	2,769
Total	$12,475	$11,322

Note 4. Receivables

Our trade receivables are generally not collateralized. At December 31, 2014 and December 31, 2013, 39% and 34% 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.

While we are continuing to collect payment on some of our receivables from our primary customer in Venezuela, the amount of outstanding receivables has increased in connection with increased activity. These receivables are not disputed, and we have not historically had material write-offs relating to this customer. Our total outstanding trade receivables in Venezuela were $670 million, or approximately 9% of our gross trade receivables, as of December 31, 2014, compared to $486 million, or approximately 8% of our gross trade receivables, as of December 31, 2013. Of the $670 million of receivables in Venezuela as of December 31, 2014, $256 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets. Of the $486 million receivables in Venezuela as of December 31, 2013, $183 million has been classified as long-term and included within “Other assets” on our consolidated balance sheets.

The following table presents a rollforward of our allowance for bad debts for 2012, 2013, and 2014.

Millions of dollars	Balance at Beginning of Period	Charged to Costs and Expenses	Write-Offs	Balance at End of Period
Year ended December 31, 2012	$137	$(40)	$(5)	$92
Year ended December 31, 2013	92	39	(14)	117
Year ended December 31, 2014	117	26	(6)	137

Note 5. 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 and totaled $227 million at December 31, 2014 and $157 million at December 31, 2013. If the average cost method had been used, total inventories would have been $38 million higher than reported at December 31, 2014 and $35 million higher than reported at December 31, 2013. The cost of the remaining inventory was recorded on the average cost method. Inventories consisted of the following:

	December 31	
Millions of dollars	2014	2013
Finished products and parts	$2,606	$2,445
Raw materials and supplies	754	720
Work in process	211	140
Total	$3,571	$3,305

Finished products and parts are reported net of obsolescence reserves of $161 million at December 31, 2014 and $130 million at December 31, 2013.

Note 6. Property, Plant, and Equipment

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

	December 31	
Millions of dollars	2014	2013
Land	$217	$213
Buildings and property improvements	3,311	2,685
Machinery, equipment, and other	19,954	17,904
Total	23,482	20,802
Less accumulated depreciation	11,007	9,480
Net property, plant, and equipment	$12,475	$11,322

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

	Buildings and Property Improvements	
	2014	2013
1 - 10 years	12%	13%
11 - 20 years	42%	43%
21 - 30 years	21%	20%
31 - 40 years	25%	24%

	Machinery, Equipment, and Other	
	2014	2013
1 - 5 years	23%	22%
6 - 10 years	70%	72%
11 - 20 years	7%	6%

Note 7. Debt

Long-term debt consisted of the following:

	December 31	
Millions of dollars	2014	2013
3.5% senior notes due August 2023	$ 1,098	$ 1,098
6.15% senior notes due September 2019	998	997
7.45% senior notes due September 2039	995	995
4.75% senior notes due August 2043	898	898
6.7% senior notes due September 2038	800	800
1.0% senior notes due August 2016	600	600
3.25% senior notes due November 2021	499	498
4.5% senior notes due November 2041	498	498
2.0% senior notes due August 2018	400	400
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
6.75% notes due February 2027	104	104
7.53% notes due May 2017	45	45
Other	42	6
Total	$ 7,854	$ 7,816
Current maturities	(14)	—
Total long-term debt	$ 7,840	$ 7,816

Senior debt

All of our senior notes and debentures rank equally with our existing and future senior unsecured indebtedness, have semiannual interest payments, and have 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 applicable 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 $3.0 billion revolving credit facility expiring in 2018. The purpose of the facility is to provide general working capital and credit for other corporate purposes. The full amount of the revolving credit facility was available as of December 31, 2014.

Debt maturities

Our long-term debt matures as follows: $14 million in 2015, $610 million in 2016, $52 million in 2017, $806 million in 2018, $1.0 billion in 2019, and the remainder in 2020 and thereafter.

Bridge facility commitment

We have obtained a commitment letter for an $8.6 billion senior unsecured bridge facility expiring in November 2015, which may be automatically extended to April 30, 2016 if the termination date under the merger agreement is extended in accordance with the terms of the merger agreement. The amount of the bridge facility commitment is greater than the expected cash consideration to be paid upon the closing of the acquisition. We have not drawn any amounts under this commitment as of December 31, 2014. We may issue debt securities, obtain bank loans or other debt financings, or use cash on hand in lieu of utilizing all or a portion of the bridge facility. See Note 2 to the consolidated financial statements for further information about the pending acquisition.

Note 8. 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. We entered into various agreements relating to the separation of KBR, including, among others, a Master Separation Agreement (MSA) and a Tax Sharing Agreement (TSA). We recorded a liability at that time reflecting the estimated fair value of the indemnities provided to KBR. Since the separation, we have recorded adjustments to reflect changes to our estimation of our remaining obligation. All such adjustments were recorded in "Income (loss) from discontinued operations, net of income tax (provision) benefit." During the first quarter of 2013, we paid $219 million to satisfy our obligation under a guarantee related to the Barracuda-Caratinga matter, a legacy KBR project. There were no amounts accrued for indemnities provided to KBR at December 31, 2014.

Tax Sharing Agreement

The TSA provides for the calculation and allocation of United States and certain other jurisdiction tax liabilities between KBR and us for the periods 2001 through the date of separation. The TSA is complex, and finalization of amounts

owed between KBR and us under the TSA can occur only after income tax audits are completed by the taxing authorities and both parties have had time to analyze the results.
During the second quarter of 2012, we sent a notice to KBR requesting the appointment of an arbitrator in accordance with the terms of the TSA. This request asked the arbitrator to find that, pursuant to the TSA, KBR owed us for certain specific tax matters. KBR denied that it owed us anything and asserted instead that we owed KBR for those tax matters.
We and KBR were involved in numerous arbitration and court proceedings relating to the dispute. In September 2014, we and KBR agreed in principle to a settlement under which we and KBR released all claims asserted against each other with respect to the disputed tax matters. In exchange for the release, among other things, KBR agreed to pay us an aggregate amount of $81 million, with $12 million paid up front, $19 million payable upon KBR receiving the benefit of certain foreign tax credits and $50 million payable in four, equal quarterly installments beginning in the fourth quarter of 2014. A definitive settlement agreement was signed in October 2014. Through December 31, 2014, we have received $25 million related to the KBR settlement.
During 2014, we recorded $63 million of income related to the settlement within “Income (loss) from discontinued operations, net of income tax (provision) benefit” in our consolidated statements of operations. This amount represents the $81 million settlement, less foreign tax credits allocated to KBR under the terms of the TSA and an immaterial receivable previously recorded.
Note 9. Commitments and Contingencies
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 an affiliate of 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. 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, as applicable, BP). There were eleven fatalities and a number of injuries as a result of the Macondo well incident.
Litigation. Numerous lawsuits relating to the Macondo well incident were filed against us, BP, Transocean and others in federal and state courts throughout the United States, most of which have been consolidated in a Multi-District Litigation (MDL) proceeding before Judge Carl Barbier in the United States Eastern District of Louisiana. Generally, those lawsuits allege either (1) damages arising from the oil spill pollution and contamination or (2) wrongful death or personal injuries. The pollution complaints include suits brought against us by governmental entities, including all of the coastal states of the Gulf of Mexico, numerous local governmental entities, the Mexican State of Yucatan, and the United Mexican States, and 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 compensatory damages, including unspecified economic damages, and punitive damages, as well as injunctive relief. 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.
The defendants in the proceedings described above have filed numerous cross claims, third party claims, and other actions against certain other defendants, including us, seeking subrogation, contribution, indemnification, including with respect to liabilities under the Oil Pollution Act of 1990 (OPA), and direct damages, and alleging negligence, gross negligence, fraudulent conduct, willful misconduct, fraudulent concealment, comparative fault, and breach of warranty of workmanlike performance.
Judge Barbier issued an order, among others, clarifying certain aspects of law applicable to the lawsuits pending in his court. The court ruled that: (1) general maritime law will apply, and therefore all claims brought under state law causes of action were dismissed; (2) general maritime law claims may be brought directly against defendants who are

non-“responsible parties” under the OPA with the exception of pure economic loss claims by plaintiffs other than commercial fishermen; (3) all claims for damages, including pure economic loss claims, may be brought under the OPA directly against responsible parties; and (4) punitive damage claims may be brought against both responsible and non-responsible parties under general maritime law. The rulings in the court's order remain subject to each applicable party's right to appeal. Certain parishes in Louisiana appealed the dismissal of their state law claims, and the United States Fifth Circuit Court of Appeals (Fifth Circuit) affirmed the dismissal. The parishes filed a petition for writ of certiorari in the United States Supreme Court (Supreme Court), which the Court denied.

We have not been named as a responsible party under the OPA, but BP has filed a claim against us for contribution with respect to liabilities incurred by BP under the OPA. In an order dismissing certain other claims, the MDL court noted that we are not liable with respect to those claims under the OPA because we are not a “responsible party” under the OPA. A group of plaintiffs appealed the order, but the Fifth Circuit dismissed the appeal.

In April 2012, BP announced that it had reached definitive settlement agreements with the Plaintiffs' Steering Committee (PSC) in the MDL to resolve the substantial majority of eligible private economic loss and medical claims stemming from the Macondo well incident (BP MDL Settlements). The PSC acts on behalf of individuals and business plaintiffs in the MDL. The BP MDL Settlements do not include claims against BP made by the United States Department of Justice (DOJ) or other federal agencies or by states and local governments. The BP MDL Settlements provide that the settlement classes are precluded from asserting compensatory damages claims against us. The economic loss settlement (BP Economic Loss Settlement) provides that, to the extent permitted by law, BP assigns to the settlement class certain of its claims, rights, and recoveries against Transocean and us for damages, including BP's alleged direct damages such as damages for clean-up expenses and damage to the well and reservoir. The MDL court has since certified the classes and granted final approval for the BP MDL Settlements. BP's medical claims settlement was final as of February 2014. BP challenged certain provisions of the BP Economic Loss Settlement in the MDL court and applicable appellate courts. In March 2014, the Fifth Circuit upheld the settlement, and BP subsequently filed a petition for writ of certiorari in the Supreme Court. In December 2014, the Supreme Court denied BP's petition.
The first phase of the MDL trial, which concluded in April 2013, covered issues arising out of the conduct and degree of culpability of various parties allegedly relevant to the loss of well control, the ensuing fire and explosion on and sinking of the Deepwater Horizon, and the initiation of the release of hydrocarbons from the Macondo well. At the conclusion of the plaintiffs' case, in March 2013, the MDL court dismissed all claims against certain defendants, leaving BP, Transocean, and us as the remaining defendants with respect to the matters addressed during the first phase of the trial.

In September 2014, we reached an agreement, subject to court approval, to settle a substantial portion of the plaintiffs' claims asserted against us relating to the Macondo well incident (our MDL Settlement). Pursuant to our MDL Settlement, we agreed to pay an aggregate of $1.1 billion, which includes legal fees and costs, into a settlement fund in three installments over two years, except that one installment of legal fees will not be paid until all of the conditions to the settlement have been satisfied or waived. Under our MDL Settlement, (1) a class of plaintiffs alleging physical damage to property or damages associated with the commercial fishing industry arising from the Macondo well incident agree to release all claims against us for punitive damages and (2) class members of the BP Economic Loss Settlement agree to release the claims against us that BP assigned to them in that settlement. We also agreed to release BP for any damages, consideration, or other relief that we provide under our MDL Settlement.

Certain conditions must be satisfied before our MDL Settlement becomes effective and the funds are released from the settlement fund. These conditions include, among others, the BP Economic Loss Settlement becoming final and effective and the issuance of a final order of the MDL court, including the resolution of any appeals, that (1) affirms we have no liability for compensatory damages to the class members of the BP Economic Loss Settlement, (2) adopts the MDL court's January 2012 order enforcing our indemnity rights against BP (see "Indemnification and Insurance" below), and (3) adopts the MDL court's prior order that, under general maritime law, pure economic loss claims by plaintiffs other than commercial fishermen may not be brought against us. In addition, we have the right to terminate our MDL Settlement if more than an agreed number of plaintiffs elect to opt out of the settlement prior to the expiration of the opt out deadline to be established by the MDL court.

Our MDL Settlement does not cover claims against us by the state governments of Alabama, Florida, Mississippi, Louisiana, or Texas, claims by our own employees, compensatory damages claims by plaintiffs in the MDL that opted out of or were excluded from the settlement class in the BP MDL Settlements, or claims by other defendants in the MDL or their respective employees. However, as discussed below, these claims have either been dismissed, are subject to dismissal, are subject to indemnification by BP pursuant to rulings of the MDL court, or are not believed to be material.

Before approving our MDL Settlement, the MDL court must certify the settlement class, the numerous class members must be notified of the proposed settlement, and the court must hold a fairness hearing. We are unable to predict when the MDL court will approve our MDL Settlement.

Subsequently in September 2014, the MDL court ruled (Phase One Ruling) that, among other things, (1) in relation to the Macondo well incident, BP's conduct was reckless, Transocean's conduct was negligent, and our conduct was negligent, (2) fault for the Macondo blowout, explosion, and spill is apportioned 67% to BP, 30% to Transocean, and

3% to us, and (3) the indemnity and release clauses in our contract with BP are valid and enforceable against BP. The MDL court did not find that our conduct was grossly negligent, thereby, subject to any appeals, eliminating our exposure in the MDL for punitive damages.

In October 2014, BP filed a motion in the MDL court to amend the court's findings, alter or amend the court's judgment, or for a new trial, and in November 2014, the MDL court denied the motion. BP has filed a notice of appeal of both the MDL court's denial of its motion and of the Phase One Ruling.

The second phase of the MDL trial was split into two parts, with testimony presented in October 2013. The first part covered attempts to collect, control, or halt the flow of hydrocarbons from the well, while the second part covered the quantification of hydrocarbons discharged from the well. The parties submitted proposed findings of fact and conclusions of law, post-trial briefs and responses during December 2013 and January 2014. According to a stipulation and post-trial filings, BP contends that 2.45 million barrels of oil were released into the Gulf of Mexico and the DOJ contends that a total of 4.2 million barrels were released. In January 2015, the MDL court ruled that, giving effect to the amount of oil collected as a result of BP’s cleanup efforts, a total of 3.19 million barrels of oil were discharged into the Gulf of Mexico for the purposes of determining the maximum penalty under the Clean Water Act (CWA).

The DOJ's civil action for CWA violations, fines, and penalties against BP Exploration, Anadarko Petroleum Corporation and Anadarko E&P Company LP, which had an approximate 25% interest in the Macondo well, is being addressed by the MDL court in another phase of the trial that began in January 2015. Also, the MDL court has scheduled a trial of seven OPA test cases which are limited to the plaintiffs and BP. The plaintiffs have dropped their general maritime law claims against us in these test cases, although BP asserts in its affirmative defenses that the damages involved were caused by third parties such as Transocean and us.

Damages for the cases tried in the MDL proceeding, including punitive damages, if any, are expected to be tried pursuant to a process to be determined by the MDL court. Under ordinary MDL procedures, such cases would, unless waived by the respective parties, be tried in the courts from which they were transferred into the MDL. A process is underway to establish a schedule for trial of the State of Alabama’s OPA and general maritime law damages claims, with a potential trial commencing in the fourth quarter of 2015.

Subject to all applicable appeals and final approvals, the following briefly summarizes the status of the various claims against us based on the various settlements and MDL court rulings described above:

- compensatory damages claims asserted against us by the members of the settlement class in the BP MDL Settlements may not be pursued under the terms of that settlement;
- compensatory damages claims asserted against us by plaintiffs in the MDL that are not members of the settlement class in the BP MDL Settlements, including plaintiffs who opted out of or were excluded from those settlements, the state governments of Alabama, Florida, Mississippi, Louisiana, and Texas, the Mexican State of Yucatan, and the United Mexican States, are either dismissed, subject to dismissal, or subject to indemnification by BP pursuant to rulings of the MDL court;
- punitive damages claims asserted against us by the members of the settlement class in our MDL Settlement are released pursuant to that settlement, and we should not otherwise be held liable for punitive damages claims asserted by any other plaintiffs in the MDL because the Phase One Ruling did not find that our conduct was grossly negligent;
- BP’s direct damages claims against us, such as claims for clean-up expenses and damage to the well and reservoir, that are assigned to members of the settlement class in the BP Economic Loss Settlement are released pursuant to our MDL Settlement;
- BP’s claim against us for contribution, indemnity, or subrogation with respect to fines and penalties under the CWA or other federal or state statute are unresolved, although we believe that the claim is without merit and is subject to a release given by BP in our contract relating to the Macondo well; and
- claims against us asserted by Transocean, and claims against us that are not included in the MDL, are unresolved, but these claims are subject to indemnification by BP pursuant to the rulings of the MDL court and we do not believe that these claims are material.

As of December 31, 2014, our remaining loss contingency liability related to the Macondo well incident was $805 million, consisting of a current portion of $367 million and a non-current portion of $439 million. The $805 million represents a $733 million loss contingency related to our MDL Settlement and a loss contingency of $72 million unrelated to that settlement. Our loss contingency liability does not include potential recoveries from our insurers or indemnification by BP. As a result of our MDL Settlement, the Phase One Ruling, and our insurance recovery related to our MDL Settlement, we recorded an adjustment of $195 million for Macondo-related items in operating income within “Corporate and other” in our consolidated statements of operations for the year ended December 31, 2014. During the fourth quarter of 2014, we made the first installment payment under our MDL Settlement in the amount of $395 million. See “Indemnification and Insurance” below for information regarding amounts that we could potentially recover from insurance and are currently unable to classify as probable.

Subject to the satisfaction of the conditions of our MDL Settlement and to the resolution of appeals of the Phase One Ruling, we believe our MDL Settlement and the Phase One Ruling have eliminated any additional material financial exposure to us in relation to the Macondo well incident. However, because our MDL Settlement is subject to court approval and other conditions and the Phase One Ruling is subject to appeals, we are unable to predict the ultimate outcome of the many lawsuits, investigations, and other matters relating to the Macondo well incident, including appeals of the Phase One Ruling, further orders and rulings of the MDL court and other courts, and indemnification and insurance arrangements. We are also unable to predict whether the court will approve our MDL Settlement or whether the conditions of our MDL Settlement will be satisfied. Accordingly, there are additional loss contingencies relating to the Macondo well incident that are reasonably possible but for which we cannot make a reasonable estimate and we may adjust our estimated loss contingency liability and our amounts recoverable from insurance in the future. In addition, applicable accounting rules and guidance may require us to recognize a loss contingency for which we may be fully indemnified, without recognizing a corresponding receivable for the amount of the indemnity payment. Depending on the developments discussed above, liabilities arising out of the Macondo well incident could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We intend to continue defending any litigation, fines, and/or penalties relating to the Macondo well incident and to vigorously pursue any damages, remedies, or other rights available to us as a result of the Macondo well incident. We have incurred and expect to continue to incur significant legal fees and costs, some of which we intend to seek recovery of through indemnity or insurance arrangements, as a result of the numerous investigations and lawsuits relating to the incident.

Regulatory Action. In October 2011, the Bureau of Safety and Environmental Enforcement (BSEE) issued a notification of Incidents of Noncompliance (INCs) to us for allegedly violating federal regulations relating to the failure to take measures to prevent the unauthorized release of hydrocarbons, the failure to take precautions to keep the Macondo well under control, the failure to cement the well in a manner that would, among other things, prevent the release of fluids into the Gulf of Mexico, and the failure to protect health, safety, property, and the environment as a result of a failure to perform operations in a safe and workmanlike manner. We have appealed the INCs, but the appeal has been suspended pending certain proceedings in the MDL trial and potential appeals. The BSEE has announced that the INCs will be reviewed for possible imposition of civil penalties once the appeal has ended. We understand that the regulations in effect at the time of the alleged violations provide for fines of up to $35,000 per day per violation.

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. The DOJ announced that it was reviewing, among other traditional criminal statutes, possible violations of and liabilities under the CWA, the OPA, and the Endangered Species Act of 1973 (ESA).

Under the CWA, civil penalties of up to $1,100 per barrel of oil discharged (or $4,300 per barrel in the case of those found to have been grossly negligent) may be assessed against responsible parties, which include an “owner, operator, or person in charge of any vessel, onshore facility, or offshore facility from which oil or a hazardous substance is discharged.” Under the OPA, responsible parties can be liable for removal and response costs for discharges of oil from vessels, onshore facilities, and offshore facilities into or upon the navigable waters of the United States, as well as for damages, including recovery costs to contain and remove discharged oil and damages for injury to natural resources and real or personal property, lost revenues, lost profits, and lost earning capacity. The cap on liability under the OPA during 2010 was the full cost of removal of the discharged oil plus up to $75 million for damages, except that the $75 million cap does not apply in the event the damage was proximately caused by gross negligence or the violation of certain federal safety, construction or operating 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 ESA establishes liability for injury and death to wildlife. The ESA provides for civil penalties for knowing violations that can range up to $25,000 per violation.

The DOJ has filed a civil action seeking damages and injunctive relief against BP Exploration, subsidiaries of Transocean Ltd., and others for violations of the CWA and the OPA. The DOJ’s complaint seeks a declaration that the defendants are strictly liable under the CWA as a result of the Macondo well incident, and seeks a declaration that the defendants are strictly liable under the OPA, with removal costs and damages to the United States far exceeding $75 million. BP Exploration 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. Under the OPA, a responsible party may make a claim for contribution against any other responsible party or against third parties it alleges contributed to or caused the oil spill. In connection with the proceedings discussed above under “Litigation,” in April 2011 BP filed a claim against us for statutory and equitable contribution with respect to liabilities incurred by BP under the OPA or another law, which subsequent court filings have indicated may include the CWA, and requested a judgment that the DOJ assert its claims for OPA financial liability directly against us. We filed a motion to dismiss BP’s claim, and that motion is pending. In July 2013, we also filed a motion for summary judgment requesting a court order that we are not liable to BP or Transocean for equitable indemnification or contribution with regard to any CWA fines and penalties that have been assessed or may be assessed against BP or Transocean. That motion is also pending.

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 civil complaint, there can be no assurance that federal governmental authorities will not bring a civil action against us under the CWA, the OPA, and/or other statutes or regulations.

In 2013, we settled the federal government's criminal investigation of us in relation to the Macondo well incident by pleading guilty to one misdemeanor violation of federal law concerning the deletion of certain computer files created after the occurrence of the Macondo well incident, paying a criminal fine of $0.2 million, and agreeing to three years' probation. In 2012, BP settled the federal criminal charges against it relating to the Macondo well incident by pleading guilty to 14 criminal charges and agreeing to, among other things, pay $4.0 billion, including approximately $1.3 billion in criminal fines, and to a term of five years' probation. In 2013, Transocean settled both federal civil and criminal claims against it arising from the Macondo well incident by pleading guilty to one misdemeanor violation of the CWA for negligent discharge of oil into the Gulf of Mexico and agreeing to pay $1.0 billion in CWA penalties and $400 million in fines and recoveries and to a term of five years' probation, among other things.

Indemnification and Insurance. Our contract with BP relating to the Macondo well generally provides for our indemnification by BP for certain 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, we have, among other things, generally agreed to indemnify BP 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 was 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. We have entered into separate indemnity agreements with Transocean and others, under which we have agreed to indemnify those parties for claims for personal injury of our employees and subcontractors and they have agreed to indemnify us for claims for personal injury of their employees and subcontractors.

In January 2012, the MDL court entered an order regarding certain indemnification matters. The court held that BP is required to indemnify us for third-party compensatory claims, or actual damages, that arise from pollution or contamination that did not originate from our property or equipment located above the surface of the land or water, even if we were found to be grossly negligent. The court also held, however, that BP does not owe us indemnity for punitive damages or for civil penalties under the CWA, if any. As discussed above, the DOJ is not seeking civil penalties from us under the CWA, but BP has filed a claim for contribution against us with respect to its liabilities. As discussed above, the Phase One Ruling found that the indemnification provisions in our contract with BP are valid and enforceable against BP.

In addition to our contractual indemnity arrangements, we had a general liability insurance program of $600 million at the time of the Macondo well incident. Our insurance was 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, as well as legal fees incurred in defending against those claims. We have received payments from our insurers with respect to covered legal fees incurred in connection with the Macondo well incident. Through December 31, 2014, we have incurred legal fees and related expenses of approximately $319 million, of which $283 million has been reimbursed under our insurance program. With respect to our MDL Settlement, we have collected $93 million under our general liability insurance program, including amounts collected subsequent to December 31, 2014.

With regard to the remaining $200 million of potential insurance recovery relating to the Macondo well incident, our insurance carriers have notified us that they do not intend to reimburse us with respect to our MDL Settlement. We disagree with our insurance carriers and intend to vigorously pursue recovery of the $200 million. Due to the uncertainty surrounding such recovery, no related amounts have been recognized in the consolidated financial statements as of December 31, 2014.

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 Securities and Exchange Commission (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 was styled Archdiocese of Milwaukee Supporting Fund (AMSF) v. Halliburton Company, et al. AMSF has changed its name to Erica P. John Fund, Inc. (the Fund). 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 our 1998 acquisition of Dresser Industries, Inc., including that we failed to timely disclose the resulting asbestos liability exposure.

In April 2005, the court appointed new co-lead counsel and named the Fund 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. 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 the Fund to re-plead some of those claims to correct deficiencies in its earlier complaint. In April 2006, the Fund 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 us.

In September 2007, the Fund filed a motion for class certification, and our response was filed in November 2007. The district court held a hearing in March 2008, and issued an order in November 2008 denying the motion for class certification. The Fund appealed the district court's order to the Fifth Circuit Court of Appeals. The Fifth Circuit affirmed the district court's order denying class certification. In May 2010, the Fund filed a writ of certiorari in the United States Supreme Court. In January 2011, the Supreme Court granted the writ of certiorari and accepted the appeal. The Court heard oral arguments in April 2011 and issued its decision in June 2011, reversing the Fifth Circuit ruling that the Fund needed to prove loss causation in order to obtain class certification. The Court's ruling was limited to the Fifth Circuit's loss causation requirement, and the case was returned to the Fifth Circuit for further consideration of our other arguments for denying class certification. The Fifth Circuit returned the case to the district court, and in January 2012 the court issued an order certifying the class. We filed a Petition for Leave to Appeal with the Fifth Circuit, which was granted. In April 2013, the Fifth Circuit issued an order affirming the District Court's order certifying the class.

We filed a writ of certiorari with the United States Supreme Court seeking an appeal of the Fifth Circuit decision. In November 2013, the Supreme Court granted our writ. Oral argument was held before the Supreme Court in March 2014. The Supreme Court issued its decision in June 2014, maintaining the presumption of class member reliance through the "fraud on the market" theory, but holding that we are entitled to rebut that presumption by presenting evidence that there was no impact on our stock price from the alleged misrepresentation. Because the district court and the Fifth Circuit denied us that opportunity, the Supreme Court vacated the Fifth Circuit's decision and remanded for further proceedings consistent with the Supreme Court decision. In December 2014, the district court held a hearing to consider whether there was an impact on our stock price from the alleged misrepresentations. Fact discovery has been stayed except as it relates to class certification. The court has not yet issued a ruling on class certification. We cannot predict the outcome or consequences of this case, which we intend to vigorously defend.

Investigations

We are conducting internal investigations of certain areas of our operations in Angola and Iraq, focusing on compliance with certain company policies, including our Code of Business Conduct (COBC), and the FCPA and other applicable laws.

In December 2010, we received an anonymous e-mail alleging that certain current and former personnel violated our COBC and the FCPA, principally through the use of an Angolan vendor. The e-mail also alleges conflicts of interest, self-dealing, and the failure to act on alleged violations of our COBC and the FCPA. We contacted the DOJ to advise them that we were initiating an internal investigation.

During the second quarter of 2012, in connection with a meeting with the DOJ and the SEC regarding the above investigation, we advised the DOJ and the SEC that we were initiating unrelated, internal investigations into payments made to a third-party agent relating to certain customs matters in Angola and to third-party agents relating to certain customs and visa matters in Iraq.

Since the initiation of the investigations described above, we have participated in meetings with the DOJ and the SEC to brief them on the status of the investigations and produced documents to them both voluntarily and as a result of SEC subpoenas to us and certain of our current and former officers and employees.

We expect to continue to have discussions with the DOJ and the SEC regarding issues relevant to the Angola and Iraq matters described above. We have engaged outside counsel and independent forensic accountants to assist us with these investigations.

During the second quarter of 2013, we received a civil investigative demand from the Antitrust Division of the DOJ regarding pressure pumping services. We have engaged in discussions with the DOJ on this matter and have provided responses to the DOJ's information requests. We understand there have been others in our industry that have received similar correspondence from the DOJ, and we do not believe that we are being singled out for any particular scrutiny.

We intend to continue to cooperate with the DOJ's and the SEC's inquiries and requests in these investigations. Because these investigations are ongoing, we cannot predict their outcome or the consequences thereof.

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;
- the Toxic Substances Control Act; and
- the Oil Pollution 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. Our Health, Safety, and Environment group has several programs in place to maintain environmental leadership and to help prevent the occurrence of environmental contamination. On occasion, in addition to the matters relating to the Macondo well incident described above, we are involved in other 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. We do not expect costs related to those claims and remediation requirements to have a material adverse effect on our liquidity, consolidated results of operations, or consolidated financial position. Excluding our loss contingency for the Macondo well incident, our accrued liabilities for environmental matters were $57 million as of December 31, 2014 and $66 million as of December 31, 2013. Because 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. Our total liability related to environmental matters covers numerous properties.

Additionally, we have subsidiaries that have been named as potentially responsible parties along with other third parties for ten federal and state Superfund sites for which we have established reserves. As of December 31, 2014, those ten sites accounted for approximately $3 million of our $57 million total environmental reserve. 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 $2.4 billion of letters of credit, bank guarantees, or surety bonds were outstanding as of December 31, 2014, including $276 million of surety bond guarantees related to our Venezuelan operations. Some of the outstanding letters of credit have triggering events that would entitle a bank to require cash collateralization.

Leases

We are party to numerous operating leases, principally for the use of land, offices, equipment, manufacturing and field facilities, and warehouses. Total rentals on our operating leases, net of sublease rentals, were $1.0 billion in 2014, $958 million in 2013, and $850 million in 2012.

Future total rentals on our noncancellable operating leases are $969 million in the aggregate, which includes the following: $283 million in 2015; $201 million in 2016; $115 million in 2017; $79 million in 2018; $54 million in 2019; and $237 million thereafter.

Note 10. Income Taxes

The components of the (provision)/benefit for income taxes on continuing operations were:

	Year Ended December 31		
Millions of dollars	2014	2013	2012
Current income taxes:			
Federal	$(959)	$(245)	$(695)
Foreign	(734)	(485)	(328)
State	(36)	(49)	(47)
Total current	(1,729)	(779)	(1,070)
Deferred income taxes:			
Federal	83	4	(168)
Foreign	357	125	15
State	14	2	(12)
Total deferred	454	131	(165)
Provision for income taxes	$(1,275)	$(648)	$(1,235)

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

	Year Ended December 31		
Millions of dollars	2014	2013	2012
United States	$3,020	$1,070	$2,826
Foreign	1,692	1,694	996
Total	$4,712	$2,764	$3,822

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		
	2014	2013	2012
United States statutory rate	35.0 %	35.0 %	35.0 %
Impact of foreign income taxed at different rates	(5.7)	(9.3)	(2.5)
Valuation allowance against tax assets	(3.6)	(0.1)	1.2
Domestic manufacturing deduction	(1.9)	(2.0)	(2.2)
State income taxes	0.8	1.7	1.6
Adjustments of prior year taxes	0.3	(0.6)	(1.3)
Other impact of foreign operations	(0.1)	(0.7)	(0.5)
Other items, net	2.3	(0.5)	1.0
Total effective tax rate on continuing operations	27.1 %	23.5 %	32.3 %

Our effective tax rate on continuing operations was 27.1% for 2014, 23.5% for 2013 and 32.3% for 2012. The 2014 effective tax rate on continuing operations was positively impacted by a $201 million net operating loss valuation allowance released as a result of a reorganization of our legal structure in Brazil. Additionally, our effective tax rate was positively impacted by lower tax rates in certain foreign jurisdictions in which we operate. Partially offsetting these items were total charges of approximately $150 million for a write-off of certain prepaid tax assets recorded in Iraq, additional tax expenses related the settlement of a research and development credit with the United States authorities, and tax expenses related to other unrecognized tax benefits, which are mostly included in "Other items, net" in the table above.

We have not provided United States income taxes and foreign withholding taxes on the undistributed earnings of foreign subsidiaries as of December 31, 2014 because we intend to permanently reinvest such earnings outside the United States. If these foreign earnings were to be repatriated in the future, the related United States tax liability may be reduced by any foreign income taxes previously paid on these earnings. As of December 31, 2014, the cumulative amount of earnings upon which United States income taxes have not been provided is approximately $6.7 billion. It is not practicable to estimate the amount of unrecognized deferred tax liability related to these earnings at this time.

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

	December 31	
Millions of dollars	2014	2013
Gross deferred tax assets:		
Accrued liabilities	$494	$600
Net operating loss carryforwards	462	481
Employee compensation and benefits	395	351
Other	315	162
Total gross deferred tax assets	1,666	1,594
Gross deferred tax liabilities:		
Depreciation and amortization	1,005	1,185
Other	111	81
Total gross deferred tax liabilities	1,116	1,266
Valuation allowances – net operating loss carryforwards	184	374
Net deferred income tax asset (liability)	$366	$(46)

At December 31, 2014, we had $1.6 billion of net operating loss carryforwards, of which $85 million will expire from 2015 through 2018, $343 million will expire from 2019 through 2023, and $211 million will expire from 2024 through 2034. The remaining balance will not expire.

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, 2012	$205		$69
Change in prior year tax positions	16		(1)
Change in current year tax positions	14		1
Cash settlements with taxing authorities	(3)		—
Lapse of statute of limitations	(4)		(1)
Balance at December 31, 2012	$228		$68
Change in prior year tax positions	(53)		(9)
Change in current year tax positions	30		1
Cash settlements with taxing authorities	(21)		(17)
Lapse of statute of limitations	(9)		(9)
Balance at December 31, 2013	$175	(a)	$34
Change in prior year tax positions	83		24
Change in current year tax positions	84		—
Cash settlements with taxing authorities	(27)		(1)
Lapse of statute of limitations	(1)		(1)
Balance at December 31, 2014	$314	(a)(b)	$56

(a) Includes $46 million as of December 31, 2014 and $27 million as of December 31, 2013 in foreign unrecognized tax benefits that would give rise to a United States tax credit. Approximately $194 million, which excludes $10 million of unrecognized tax benefits covered by an indemnification asset, as of December 31, 2014 and $138 million as of December 31, 2013, 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 $42 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 2005. 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 for the tax years 2012 through 2013 are open for review, 2003 through 2009 are under appeal pending final calculation of certain tax attribute carryforwards, and 2010 through 2011 are under examination by the Internal Revenue Service.

Note 11. Shareholders’ Equity
Shares of common stock
The following table summarizes total shares of common stock outstanding:

	December 31	
Millions of shares	2014	2013
Issued	1,071	1,072
In treasury	(223)	(223)
Total shares of common stock outstanding	848	849

Our Board of Directors has authorized a program to repurchase our common stock from time to time. During the year ended December 31, 2014, under that program we repurchased approximately 13.3 million shares of our common stock for a total cost of $800 million. In July 2014, our Board of Directors increased the authorization to repurchase our common stock by approximately $4.8 billion. Approximately $5.7 billion remains authorized for repurchases as of December 31, 2014. 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, 2014, we repurchased approximately 201 million shares of our common stock for a total cost of approximately $8.4 billion.
Preferred stock
Our preferred stock consists of five million total authorized shares at December 31, 2014, of which none are issued.
Accumulated other comprehensive loss
Accumulated other comprehensive loss consisted of the following:

	December 31	
Millions of dollars	2014	2013
Defined benefit and other postretirement liability adjustments (a)	$(326)	$(241)
Cumulative translation adjustment	(70)	(69)
Other	(3)	3
Total accumulated other comprehensive loss	$(399)	$(307)

(a) Included net actuarial losses for our international pension plans of $298 million at December 31, 2014 and $222 million at December 31, 2013.

Note 12. Stock-based Compensation
The following table summarizes stock-based compensation costs for the years ended December 31, 2014, 2013, and 2012.

	Year Ended December 31		
Millions of dollars	2014	2013	2012
Stock-based compensation cost	$298	$264	$217
Tax benefit	(90)	(81)	(67)
Stock-based compensation cost, net of tax	$208	$183	$150

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, stock value equivalent awards, or incentive stock options outstanding.

Under the terms of the Stock Plan, approximately 172 million shares of common stock have been reserved for issuance to employees and non-employee directors. At December 31, 2014, approximately 15 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. 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 2014.

	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, 2014	18.1	$36.57		
Granted	5.2	59.43		
Exercised	(5.4)	34.62		
Forfeited/expired	(0.5)	44.17		
Outstanding at December 31, 2014	17.4	$43.74	7.3	$56
Exercisable at December 31, 2014	7.7	$35.83	5.6	$45

The total intrinsic value of options exercised was $151 million in 2014, $93 million in 2013, and $12 million in 2012. As of December 31, 2014, there was $109 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 two years.
Cash received from option exercises was $332 million during 2014, $277 million during 2013, and $107 million during 2012.
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		
	2014	2013	2012
Expected term (in years)	5.23	5.27	5.21
Expected volatility	37%	40%	46%
Expected dividend yield	0.94 - 1.77%	0.94 - 1.33%	0.99 – 1.24%
Risk-free interest rate	1.57 - 1.86%	0.77 - 1.73%	0.65 – 1.15%
Weighted average grant-date fair value per share	$19.26	$14.34	$11.99

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.

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The following table represents our restricted stock awards and restricted stock units granted, vested, and forfeited during 2014.

	Number of Shares (in millions)	Weighted Average Grant-Date Fair Value per Share
Nonvested shares at January 1, 2014	15.7	$ 37.43
Granted	6.2	58.21
Vested	(4.7)	35.10
Forfeited	(1.1)	41.63
Nonvested shares at December 31, 2014	16.1	$ 45.88

The weighted average grant-date fair value of shares granted during 2013 was $42.93 and during 2012 was $32.17. The total fair value of shares vested during 2014 was $278 million, during 2013 was $208 million, and during 2012 was $126 million. As of December 31, 2014, there was $530 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 four 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. For the year ended December 31, 2012, the ESPP contained two six-month offering periods commencing on January 1 and July 1. Beginning in 2013, the ESPP contained four three-month offering periods commencing on January 1, April 1, July 1, and October 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. The stock to be offered may be authorized but unissued common shares or treasury shares. As of December 31, 2014, 35 million shares have been sold through the ESPP since the inception of the plan and 9 million shares are available for future issuance.

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:

	Year Ended December 31		
	2014	2013	2012
Expected volatility	23 %	27 %	49 %
Expected dividend yield	1.07 %	1.12 %	1.16 %
Risk-free interest rate	0.04 %	0.06 %	0.11 %
Weighted average grant-date fair value per share	$ 11.80	$ 8.40	$ 8.93

Note 13. 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. Differences between basic and diluted weighted average common shares outstanding for all periods presented resulted from the dilutive effect of awards granted under our stock incentive plans.

Excluded from the computation of diluted income per share are options to purchase two million shares of common stock that were outstanding in 2014, three million shares of common stock that were outstanding in 2013, and seven million shares of common stock that were outstanding in 2012. 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 14. Financial Instruments and Risk Management

At December 31, 2014, we held $103 million of investments in fixed income securities with maturities ranging from less than one year to November 2019, compared to $373 million of investments in fixed income securities held at December 31, 2013. These securities are accounted for as available-for-sale and recorded at fair value as follows:

	December 31, 2014			December 31, 2013		
Millions of dollars	Level 1	Level 2	Total	Level 1	Level 2	Total
Fixed Income Securities:						
U.S. treasuries (a)	$—	$—	$—	$100	$—	$100
Other (b)	—	103	103	—	273	273
Total	$—	$103	$103	$100	$273	$373

(a) These securities are classified as "Other current assets" in our consolidated balance sheets.

(b) Of these securities, $56 million are classified as “Other current assets” and $47 million are classified as “Other assets” on our consolidated balance sheets as of December 31, 2014, compared to $139 million classified as "Other current assets" and $134 million classified as "Other assets" as of December 31, 2013. These securities consist primarily of municipal bonds, corporate bonds, and other debt instruments.

Our Level 1 asset fair values are based on quoted prices in active markets and our Level 2 asset fair values are based on quoted prices for identical assets in less active markets. We have no financial instruments measured at fair value using unobservable inputs (Level 3). The carrying amount of cash and equivalents, receivables, and accounts payable, as reflected in the consolidated balance sheets, approximates fair value due to the short maturities of these instruments.

The carrying amount and fair value of our long-term debt is as follows:

	December 31, 2014				December 31, 2013			
Millions of dollars	Level 1	Level 2	Total fair value	Carrying value	Level 1	Level 2	Total fair value	Carrying value
Long-term debt	$4,822	$4,257	$9,079	$7,840	$8,405	$292	$8,697	$7,816

Our Level 1 debt fair values are calculated using quoted prices in active markets for identical liabilities with transactions occurring on the last two days of year-end. Our Level 2 debt fair values are calculated using significant observable inputs for similar liabilities where estimated values are determined from observable data points on our other bonds and on other similarly rated corporate debt or from observable data points of transactions occurring prior to two days from year-end and adjusting for changes in market conditions. We have no debt measured at fair value using unobservable inputs (Level 3).

We are exposed to market risk from changes in foreign currency exchange rates and interest rates. We selectively manage these exposures through the use of derivative instruments, including forward foreign exchange contracts, foreign exchange options, and interest rate swaps. The objective of our risk management strategy is to minimize the volatility from fluctuations in foreign currency and interest rates. We do not use derivative instruments for trading purposes. The fair value of our forward contracts, options, and interest rate swaps was not material as of December 31, 2014 or December 31, 2013. The counterparties to our derivatives are global commercial and investment banks.

Foreign currency exchange risk

We have operations in many international locations and are involved in transactions denominated in currencies other than the United States dollar, our functional currency, which exposes us to foreign currency exchange rate risk. Techniques in managing foreign currency exchange risk include, but are not limited to, foreign currency borrowing and investing and the use of currency exchange instruments. We attempt to selectively manage significant exposures to potential foreign currency exchange losses based on 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 minimize the risk that our cash flows from the sale and purchase of services and products in foreign currencies will be adversely affected by changes in exchange rates.

We use forward contracts and options to manage our exposure to fluctuations in the currencies of certain countries in which we do business internationally. These instruments are not treated as hedges for accounting purposes, generally have an expiration date of one year or less, and are not exchange traded. While these 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 of these instruments may limit our ability to benefit from favorable fluctuations in foreign currency exchange rates.

Derivatives 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 exposure in non-traded currencies and recognize that pricing for the services and products offered in these countries should account for the cost of exchange rate devaluations. We have historically incurred transaction losses in non-traded currencies.

The notional amounts of open foreign exchange derivatives were $662 million at December 31, 2014 and $769 million at December 31, 2013. The notional amounts of these instruments 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. As such, cash flows related to these contracts are typically not material. The amounts exchanged are calculated by reference to the notional amounts and by other terms of the contracts, such as exchange rates.

Interest rate risk

We are subject to interest rate risk on our existing long-term debt, debt potentially issued in the future, and some of our long-term investments in fixed income securities. Our short-term borrowings and short-term investments in fixed income securities do not give rise to significant interest rate risk due to their short-term nature. We had fixed rate long-term debt totaling $7.8 billion at December 31, 2014 and December 31, 2013, with none maturing before 2016. We also had $47 million of long-term investments in fixed income securities at December 31, 2014 with maturities that extend through November 2019.

We maintain an interest rate management strategy that is intended to mitigate the exposure to changes in interest rates in the aggregate for our debt portfolio. We hold a series of interest rate swaps relating to three of our debt instruments with a total notional amount of $1.5 billion at a weighted-average, LIBOR-based, floating rate of 3.8% as of December 31, 2014. We utilize interest rate swaps to effectively convert a portion of our fixed rate debt to floating rates. These interest rate swaps, which expire when the underlying debt matures, are designated as fair value hedges of the underlying debt and are determined to be highly effective. The fair value of our interest rate swaps is included in “Other assets” in our consolidated balance sheets as of December 31, 2014 and December 31, 2013. The fair value of our interest rate swaps was determined using an income approach model with inputs, such as the notional amount, LIBOR rate spread, and settlement terms that are observable in the market or can be derived from or corroborated by observable data (Level 2). These derivative instruments are marked to market with gains and losses recognized currently in interest expense to offset the respective gains and losses recognized on changes in the fair value of the hedged debt. At December 31, 2014, we had fixed rate debt aggregating $6.3 billion and variable rate debt aggregating $1.5 billion, after taking into account the effects of the interest rate swaps.

Credit risk

Financial instruments that potentially subject us to concentrations of credit risk are primarily cash equivalents, investments in fixed income securities, and trade receivables. It is our practice to place our cash equivalents and investments in fixed income securities in high quality investments with various institutions. We derive the majority of our revenue from selling products and providing services to the energy industry. Within the energy industry, our trade receivables are generated from a broad and diverse group of customers. As of December 31, 2014, 39% of our gross trade receivables were in the United States and 9% were in Venezuela, compared to 34% in the United States and 8% in Venezuela at December 31, 2013. We maintain an allowance for losses based upon the expected collectability of all trade accounts receivable.

We do not have any significant concentrations of credit risk with any individual counterparty to our derivative contracts. We select counterparties to those contracts based on our belief that each counterparty’s profitability, balance sheet, and capacity for timely payment of financial commitments is unlikely to be materially adversely affected by foreseeable events.

Note 15. 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 $347 million in 2014, $313 million in 2013, and $293 million in 2012;
-

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. The unfunded obligations and net periodic benefit cost of our United States defined benefit plans were not material for the periods presented; and

- our postretirement plans other than pensions are offered to specific eligible employees. The accumulated benefit obligations and net periodic benefit cost for these plans were not material for the periods presented.

Funded status

For our international pension plans, at December 31, 2014, the projected benefit obligation was $1.2 billion and the fair value of plan assets was $891 million, which resulted in an unfunded obligation of $347 million. At December 31, 2013, the projected benefit obligation was $1.2 billion and the fair value of plan assets was $887 million, which resulted in an unfunded obligation of $268 million. The accumulated benefit obligation for our international plans was $1.2 billion at December 31, 2014 and $1.1 billion at December 31, 2013.

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The following table presents additional information about our international pension plans.

Millions of dollars	December 31 2014	2013
Amounts recognized on the Consolidated Balance Sheets		
Accrued employee compensation and benefits	$ 22	$ 17
Employee compensation and benefits	325	251
Pension plans in which projected benefit obligation exceeded plan assets		
Projected benefit obligation	$ 1,232	$ 1,123
Fair value of plan assets	884	854
Pension plans in which accumulated benefit obligation exceeded plan assets		
Accumulated benefit obligation	$ 1,120	$ 1,046
Fair value of plan assets	860	854

Fair value measurements of plan assets

Our Level 1 plan asset fair values are based on quoted prices in active markets for identical assets, our Level 2 plan asset fair values are based on significant observable inputs for similar assets, and our Level 3 plan asset fair values are based on significant unobservable inputs.

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	Level 1	Level 2	Level 3	Total
Common/collective trust funds				
Equity funds (a)	$ —	$ 320	$ —	$ 320
Bond funds (b)	—	197	70	267
Alternatives fund (c)	—	148	—	148
Real estate funds (d)	—	86	—	86
Other assets	6	33	31	70
Fair value of plan assets at December 31, 2014	$ 6	$ 784	$ 101	$ 891
Common/collective trust funds (e)				
Equity funds	$ —	$ 247	$ —	$ 247
Bond funds	—	118	—	118
Balanced funds	—	13	—	13
Non-United States equity securities	165	—	—	165
United States equity securities	139	—	—	139
Corporate bonds	—	110	—	110
Other assets	2	59	34	95
Fair value of plan assets at December 31, 2013	$ 306	$ 547	$ 34	$ 887

(a) Strategy is to invest in diversified funds of global common stocks.

(b) Strategy is to invest in diversified funds of fixed income securities of varying geographies and credit quality and whose cash flows approximate the maturities of the benefit obligation.

(c) Strategy is to invest in a fund of diversifying investments, including but not limited to reinsurance, commodities, and currencies.

(d) Strategy is to invest in diversified funds of real estate investment trusts and private real estate.

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

Common/collective trust funds are valued at the net asset value of units held by the plans at year-end.

Equity securities are traded in active markets and valued based on their quoted fair value by independent pricing vendors. Corporate bonds are valued using quotes from independent pricing vendors based on recent trading activity and other relevant information, including other observable inputs such as market interest rate curves, referenced credit spreads, and estimated prepayment rates, where applicable.

Our investment strategy varies by country depending on the circumstances of the underlying 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 Kingdom pension plan, which constituted 80% of our international pension plans' projected benefit obligation at December 31, 2014 and is no longer accruing service benefits, we implemented an investment strategy in 2014 that aims to achieve full funding of the benefit obligation, with the plan's assets increasingly composed of investments whose cash flows match the maturities of the obligation.

Net periodic benefit cost

Net periodic benefit cost for our international pension plans was $36 million in 2014, $32 million in 2013, and $26 million in 2012.

Actuarial assumptions

Certain weighted-average actuarial assumptions used to determine benefit obligations of our international pension plans at December 31 were as follows:

	2014	2013
Discount rate	4.1%	4.8%
Rate of compensation increase	5.3%	5.5%

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

	2014	2013	2012
Discount rate	4.8%	4.8%	5.2%
Expected long-term return on plan assets	6.4%	6.4%	6.5%
Rate of compensation increase	5.4%	5.5%	5.4%

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.

Other information

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 $14 million to our international pension plans in 2015.

Benefit payments. The following table presents expected benefit payments over the next 10 years for our international pension plans.

Millions of dollars	
2015	$46
2016	35
2017	37
2018	36
2019	43
Years 2020 - 2024	341

Note 16. New Accounting Pronouncements

Revenue Recognition

In May 2014, the Financial Accounting Standards Board (FASB) and the International Accounting Standards Board (IASB) issued a comprehensive new revenue recognition standard that will supersede existing revenue recognition guidance under United States generally accepted accounting principles (U.S. GAAP) and International Financial

Reporting Standards (IFRS). The issuance of this guidance completes the joint effort by the FASB and the IASB to improve financial reporting by creating common revenue recognition guidance for U.S. GAAP and IFRS.
The core principle of the new guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The standard creates a five-step model that requires companies to exercise judgment

when considering the terms of a contract and all relevant facts and circumstances. The standard allows for several transition methods: (a) a full retrospective adoption in which the standard is applied to all of the periods presented, or (b) a modified retrospective adoption in which the standard is applied only to the most current period presented in the financial statements, including additional disclosures of the standard's application impact to individual financial statement line items.

This standard is effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. We are currently evaluating this standard and our existing revenue recognition policies to determine which contracts in the scope of the guidance will be affected by the new requirements and what impact they would have on our consolidated financial statements upon adoption of this standard. We have not yet determined which transition method we will utilize upon adoption.

Discontinued Operations

In April 2014, the FASB issued a new accounting standard update related to discontinued operations, which added criteria where only disposals that represent a strategic shift in operations should be presented as discontinued operations. It also allows an entity to present a disposal as discontinued operations even when it has continuing cash flows and significant continuing involvement with the disposed component. The update will also require expanded disclosures for discontinued operations and individually significant components of an entity that does not qualify for discontinued operations reporting. The standard is effective for annual periods beginning on or after December 15, 2014 and interim periods within that year. We are evaluating the new standard and do not expect it will have a material effect on our consolidated financial statements upon adoption based on our current business. Subject to certain conditions and events that may occur in 2015 related to the pending acquisition of Baker Hughes, this new pronouncement may have a material impact to our consolidated financial statements in regards to our presentation of discontinued operations. See Note 2 to the consolidated financial statements for further information about the pending acquisition.

HALLIBURTON COMPANY
Selected Financial Data
(Unaudited)

Millions of dollars and shares except per share and employee data	Year ended December 31 2014	2013	2012	2011	2010
Total revenue	$32,870	$29,402	$28,503	$24,829	$17,973
Total operating income	$5,097	$3,138	$4,159	$4,737	$3,009
Nonoperating expense, net	(385)	(374)	(337)	(288)	(354)
Income from continuing operations before income taxes	4,712	2,764	3,822	4,449	2,655
Provision for income taxes	(1,275)	(648)	(1,235)	(1,439)	(853)
Income from continuing operations	$3,437	$2,116	$2,587	$3,010	$1,802
Income (loss) from discontinued operations, net	64	19	58	(166)	40
Net income	$3,501	$2,135	$2,645	$2,844	$1,842
Noncontrolling interest in net income of subsidiaries	(1)	(10)	(10)	(5)	(7)
Net income attributable to company	$3,500	$2,125	$2,635	$2,839	$1,835
Amounts attributable to company shareholders:					
Income from continuing operations	$3,436	$2,106	$2,577	$3,005	$1,795
Income (loss) from discontinued operations, net	64	19	58	(166)	40
Net income	3,500	2,125	2,635	2,839	1,835
Basic income per share attributable to shareholders:					
Income from continuing operations	$4.05	$2.35	$2.78	$3.27	$1.98
Net income	4.13	2.37	2.85	3.09	2.02
Diluted income per share attributable to shareholders:					
Income from continuing operations	4.03	2.33	2.78	3.26	1.97
Net income	4.11	2.36	2.84	3.08	2.01
Cash dividends per share	0.63	0.525	0.36	0.36	0.36
Return on average shareholders’ equity	23.40%	14.45%	18.17%	24.06%	19.17%
Financial position:					
Net working capital	$9,185	$8,678	$8,334	$7,456	$6,129
Total assets	32,240	29,223	27,410	23,677	18,297
Property, plant, and equipment, net	12,475	11,322	10,257	8,492	6,842
Long-term debt (including current maturities)	7,854	7,816	4,820	4,820	3,824
Total shareholders’ equity	16,298	13,615	15,790	13,216	10,387
Total capitalization	24,271	21,569	20,764	18,097	14,241
Basic weighted average common shares outstanding	848	898	926	918	908
Diluted weighted average common shares outstanding	852	902	928	922	911
Other financial data:					
Capital expenditures	$3,283	$2,934	$3,566	$2,953	$2,069
Long-term borrowings (repayments), net	—	2,968	—	978	(790)
Depreciation, depletion, and amortization	2,126	1,900	1,628	1,359	1,119
Payroll and employee benefits	9,026	8,421	7,722	6,756	5,370
Number of employees	80,000	77,000	73,000	68,000	58,000

HALLIBURTON COMPANY
Quarterly Data and Market Price Information
(Unaudited)

Millions of dollars except per share data	Quarter First [1]	Second	Third	Fourth	Year
2014					
Revenue	$7,348	$8,051	$8,701	$8,770	$32,870
Operating income	970	1,194	1,634	1,299	5,097
Net income	616	775	1,205	905	3,501
Amounts attributable to company shareholders:					
Income from continuing operations	623	776	1,137	900	3,436
Income (loss) from discontinued operations	(1)	(2)	66	1	64
Net income attributable to company	622	774	1,203	901	3,500
Basic income per share attributable to company shareholders:					
Income from continuing operations	0.73	0.92	1.34	1.06	4.05
Income from discontinued operations	—	—	0.08	—	0.08
Net income	0.73	0.92	1.42	1.06	4.13
Diluted income per share attributable to company shareholders:					
Income from continuing operations	0.73	0.91	1.33	1.06	4.03
Income from discontinued operations	—	—	0.08	—	0.08
Net income	0.73	0.91	1.41	1.06	4.11
Cash dividends paid per share	0.15	0.15	0.15	0.18	0.63
Common stock prices [2]					
High	59.99	71.26	74.33	64.88	74.33
Low	47.60	57.13	63.06	37.21	37.21
2013					
Revenue	$6,974	$7,317	$7,472	$7,639	$29,402
Operating income (loss)	(98)	984	1,108	1,144	3,138
Net income (loss)	(16)	648	708	795	2,135
Amounts attributable to company shareholders:					
Income (loss) from continuing operations	(13)	642	707	770	2,106
Income (loss) from discontinued operations	(5)	2	(1)	23	19
Net income (loss) attributable to company	(18)	644	706	793	2,125
Basic income per share attributable to company shareholders:					
Income (loss) from continuing operations	(0.01)	0.69	0.79	0.91	2.35
Income (loss) from discontinued operations	(0.01)	0.01	—	0.02	0.02
Net income (loss)	(0.02)	0.70	0.79	0.93	2.37
Diluted income per share attributable to company shareholders:					
Income (loss) from continuing operations	(0.01)	0.69	0.79	0.90	2.33
Income (loss) from discontinued operations	(0.01)	—	—	0.03	0.03
Net income (loss)	(0.02)	0.69	0.79	0.93	2.36
Cash dividends paid per share	0.125	0.125	0.125	0.15	0.525
Common stock prices [2]					
High	43.96	45.75	50.50	56.52	56.52
Low	35.07	36.77	41.86	47.99	35.07

(1) Includes a $1.0 billion, pre-tax, charge in the first quarter of 2013 related to the Macondo well incident.
(2) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) under the captions “Compensation Discussion and Analysis,” “Compensation Committee Report,” “Summary Compensation Table,” “Grants of Plan-Based Awards in Fiscal 2014,” “Outstanding Equity Awards at Fiscal Year End 2014,” “2014 Option Exercises and Stock Vested,” “2014 Nonqualified Deferred Compensation,” “Employment Contracts and Change-in-Control Arrangements,” “Post-Termination or Change-in-Control 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 2015 Annual Meeting of Stockholders (File No. 001-03492) 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 Halliburton Company as required by Part II, Item 8, are included on pages 41 and 42 and pages 43 through 73 of this annual report. See index on page (i).

2. Financial Statement Schedules:
   The schedules listed in Rule 5-04 of Regulation S-X (17 CFR 210.5-04) have been omitted because they are not applicable or the required information is shown in the consolidated financial statements or notes thereto.

3. Exhibits:

Exhibit Number	Exhibits
2.1	Agreement and Plan of Merger, dated as of November 16, 2014, among Halliburton Company, Red Tiger LLC and Baker Hughes Incorporated (incorporated by reference to Exhibit 2.1 to Halliburton's Form 8-K filed November 18, 2014, File No. 001-03492).
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. 001-03492).
3.2	By-laws of Halliburton Company revised effective February 12, 2014 (incorporated by reference to Exhibit 3.1 to Halliburton's Form 8-K filed February 18, 2014, File No. 001-03492).
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. 001-03492).
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. 001-03492).
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. 001-03492).
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. 001-03492).

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. 001-03492).
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. 001-03492).
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. 001-03492).
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. 001-03492).
4.9	Copies of instruments that define the rights of holders of miscellaneous long-term notes of Halliburton Company and its subsidiaries have not been filed with the Commission. Halliburton Company agrees to furnish copies of these instruments upon request.
4.10	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. 001-03492).
4.11	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).
4.12	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. 001-03492).
4.13	Third Supplemental Indenture dated as of December 12, 2003 among DII Industries, LLC, Halliburton Company 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. 001-03492).
4.14	Indenture dated as of October 17, 2003 between Halliburton Company 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. 001-03492).
4.15	Second Supplemental Indenture dated as of December 15, 2003 between Halliburton Company 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. 001-03492).
4.16	Form of note of 7.6% debentures due 2096 (included as Exhibit A to Exhibit 4.15 above).

	4.17	Fourth Supplemental Indenture, dated as of September 12, 2008, between Halliburton Company 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. 001-03492).
	4.18	Form of Global Note for Halliburton's 5.90% Senior Notes due 2018 (included as part of Exhibit 4.17).
	4.19	Form of Global Note for Halliburton's 6.70% Senior Notes due 2038 (included as part of Exhibit 4.17).
	4.20	Fifth Supplemental Indenture, dated as of March 13, 2009, between Halliburton Company 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. 001-03492).
	4.21	Form of Global Note for Halliburton's 6.15% Senior Notes due 2019 (included as part of Exhibit 4.20).
	4.22	Form of Global Note for Halliburton's 7.45% Senior Notes due 2039 (included as part of Exhibit 4.20).
	4.23	Sixth Supplemental Indenture, dated as of November 14, 2011, between Halliburton Company 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 November 14, 2011, File No. 001-03492).
	4.24	Form of Global Note for Halliburton's 3.25% Senior Notes due 2021 (included as part of Exhibit 4.23).
	4.25	Form of Global Note for Halliburton's 4.50% Senior Notes due 2041 (included as part of Exhibit 4.23).
	4.26	Seventh Supplemental Indenture, dated as of August 5, 2013, between Halliburton Company and The Bank of New York Mellon Trust Company, N.A., as successor trustee to JPMorgan Chase Bank (incorporated by reference to Exhibit 4.2 of Halliburton's Form 8-K filed August 5, 2013, File No. 001-03492).
	4.27	Form of Global Note for Halliburton's 1.00% Senior Notes due 2016 (included as part of Exhibit 4.26).
	4.28	Form of Global Note for Halliburton's 2.00% Senior Notes due 2018 (included as part of Exhibit 4.26).
	4.29	Form of Global Note for Halliburton's 3.50% Senior Notes due 2023 (included as part of Exhibit 4.26).
	4.30	Form of Global Note for Halliburton's 4.75% Senior Notes due 2043 (included as part of Exhibit 4.26).
†	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. 001-03492).
†	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. 001-03492).
†	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. 001-03492).
†	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. 001-03492).
†	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. 001-03492).
	10.8	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. 001-03492).
	10.9	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. 001-03492).
	10.10	Form of Indemnification Agreement for Officers (first elected after January 1, 2013) (incorporated by reference to Exhibit 10.2 to Halliburton's Form 10-Q for the quarter ended March 31, 2013, File No. 001-03492).
	10.11	Form of Indemnification Agreement for Directors (first elected after January 1, 2013) (incorporated by reference to Exhibit 10.1 of Halliburton's Form 8-K filed March 22, 2013, File No. 001-03492).
†	10.12	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. 001-03492).
†	10.13	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. 001-03492).
†	10.14	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. 001-03492).
†	10.15	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. 001-03492).
†	10.16	Halliburton Company Directors' Deferred Compensation Plan, as amended and restated effective as of May 16, 2012 (incorporated by reference to Exhibit 10.5 to Halliburton's Form 10-Q for the quarter ended June 30, 2012, File No. 001-03492).
†	10.17	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. 001-03492).

†	10.18	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. 001-03492).

†	10.19	Executive Agreement (Lawrence J. Pope) (incorporated by reference to Exhibit 10.1 to Halliburton’s Form 8-K filed December 12, 2008, File No. 001-03492).
†	10.20	Halliburton Company Stock and Incentive Plan, as amended and restated effective February 20, 2013 (incorporated by reference to Appendix B of Halliburton's proxy statement filed April 2, 2013, File No. 001-03492).
†	10.21	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. 001-03492).
†	10.22	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. 001-03492).
†	10.23	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. 001-03492).
†	10.24	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. 001-03492).
†	10.25	Form of Non-Employee Director Restricted Stock Unit Agreement (Director Plan) (incorporated by reference to Exhibit 99.8 of Halliburton's Form S-8 filed June 22, 2012, Registration No. 333-182284).
†	10.26	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. 001-03492).
†	10.27	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. 001-03492).
†	10.28	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. 001-03492).
†	10.29	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. 001-03492).
†	10.30	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. 001-03492).
†	10.31	Amendment No. 1 to 2008 Halliburton Elective Deferral Plan, as amended and restated effective January 1, 2008 (incorporated by reference to Exhibit 10.41 to Halliburton’s Form 10-K for the year ended December 31, 2010, File No. 001-03492).
†	10.32	Executive Agreement (Joe D. Rainey) (incorporated by reference to Exhibit 10.43 to Halliburton’s Form 10-K for the year ended December 31, 2010, File No. 001-03492).
	10.33	

U.S. $2,000,000,000 Five Year Revolving Credit Agreement among Halliburton Company, as Borrower, the Banks party thereto, and Citibank, N.A., as Agent (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed February 23, 2011, File No. 001-03492).

†	10.34	First Amendment dated February 10, 2011 to Halliburton Company Employee Stock Purchase Plan, as amended and restated effective February 11, 2009 (incorporated by reference to Exhibit 10.2 to Halliburton's Form 10-Q for the quarter ended March 31, 2011, File No. 001-03492).
†	10.35	First Amendment to the Retirement Plan for the Directors of Halliburton Company, effective September 1, 2007 (incorporated by reference to Exhibit 10.3 to Halliburton's Form 10-Q for the quarter ended March 31, 2011, File No. 001-03492).
†	10.36	Executive Agreement (Christian A. Garcia) (incorporated by reference to Exhibit 10.40 to Halliburton's Form 10-K for the year ended December 31, 2011, File No. 001-03492).
†	10.37	First Amendment to Halliburton Company Restricted Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.41 to Halliburton's Form 10-K for the year ended December 31, 2011, File No. 001-03492).
†	10.38	Form of Restricted Stock Agreement (Section 16 officers) (incorporated by reference to Exhibit 10.42 to Halliburton's Form 10-K for the year ended December 31, 2011, File No. 001-03492).
†	10.39	Form of Non-Employee Director Restricted Stock Unit Agreement (Stock and Incentive Plan) (incorporated by reference to Exhibit 99.9 of Halliburton's Form S-8 filed June 22, 2012, Registration No. 333-182284).
†	10.40	Second Amendment to Restricted Stock Plan for Non-Employee Directors of Halliburton Company (incorporated by reference to Exhibit 10.4 to Halliburton's Form 10-Q for the quarter ended June 30, 2012, File No. 001-03492).
†	10.41	Third Amendment to Restricted Stock Plan for Non-Employee Directors of Halliburton Company effective December 1, 2012 (incorporated by reference to Exhibit 10.44 to Halliburton's Form 10-K for the year ended December 31, 2012, File No. 001-03492).
†	10.42	First Amendment dated December 1, 2012 to Halliburton Company Directors' Deferred Compensation Plan, as amended and restated effective May 16, 2012 (incorporated by reference to Exhibit 10.45 to Halliburton's Form 10-K for the year ended December 31, 2012, File No. 001-03492).
†	10.43	Executive Agreement (Jeffrey A. Miller) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 8-K filed September 21, 2012, File No. 001-03492).
†	10.44	Second Amendment dated December 11, 2012 to Halliburton Company Employee Stock Purchase Plan, as amended and restated effective February 11, 2009 (incorporated by reference to Exhibit 10.47 to Halliburton's Form 10-K for the year ended December 31, 2012, File No. 001-03492).
†	10.45	Executive Agreement (Myrtle L. Jones) (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended March 31, 2013, File No. 001-03492).
	10.46	First Amendment dated April 23, 2013 of the Five Year Revolving Credit Agreement among Halliburton Company, as Borrower, the Banks party thereto, and Citibank, N.A., as Agent effective February 22, 2011 (incorporated by reference to Exhibit 10.4 to Halliburton's Form 10-Q for the quarter ended March 31, 2013, File No. 001-03492).

	10.47	Underwriting Agreement, dated July 29, 2013, among Halliburton Company and Citigroup Global Markets Inc., Deutsche Bank Securities Inc., HSBC Securities (USA) Inc., RBS Securities Inc. and the several other underwriters identified therein (incorporated by reference to Exhibit 1.1 of Halliburton's Form 8-K filed August 1, 2013, File No. 001-03492).
†	10.48	Executive Agreement (Robb L. Voyles) (incorporated by reference to Exhibit 10.48 to Halliburton's Form 10-K filed February 7, 2014, File No. 001-03492).

†	10.49	Executive Agreement (Timothy McKeon) (incorporated by reference to Exhibit 10.49 to Halliburton's Form 10-K filed February 7, 2014, File No. 001-03492).
†	10.50	Executive Agreement (Charles E. Geer, Jr.) (incorporated by reference to Exhibit 10.2 to Halliburton's Form 8-K filed December 9, 2014, File No. 001-03492).
	10.51	HESI Punitive Damages and Assigned Claims Settlement Agreement dated September 2, 2014, entered into between Halliburton Company and Halliburton Energy Services, Inc. and counsel for The Plaintiffs Steering Committee in MDL 2179 and the Deepwater Horizon Economic and Property Damages Settlement Class (incorporated by reference to Exhibit 10.1 to Halliburton's Form 10-Q for the quarter ended September 30, 2014, File No. 001-03492).
*	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 signed in January 2015: Abdulaziz F. Al Khayyal Alan M. Bennett James R. Boyd Milton Carroll Nance K. Dicciani Murry S. Gerber José C. Grubisich Abdallah S. Jum'ah Robert A. Malone J. Landis Martin Jeffrey A. Miller 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.
*	95	Mine Safety Disclosures.
*	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.
† Management contracts or compensatory plans or arrangements.

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 24th day of February, 2015.

HALLIBURTON COMPANY

By	/s/ David J. Lesar David J. Lesar Chairman of the Board 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 24th day of February, 2015.

Signature	Title
/s/ David J. Lesar David J. Lesar	Chairman of the Board, Director, and Chief Executive Officer
/s/ Christian A. Garcia Christian A. Garcia	Senior Vice President, Finance and Acting Chief Financial Officer
/s/ Charles E. Geer, Jr. Charles E. Geer, Jr.	Vice President and Corporate Controller

Signature	Title
* Abdulaziz F. Al Khayyal Abdulaziz F. Al Khayyal	Director
* 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
* Murry S. Gerber Murry S. Gerber	Director
* José C. Grubisich José C. Grubisich	Director
* Abdallah S. Jum'ah Abdallah S. Jum'ah	Director
* Robert A. Malone Robert A. Malone	Director
* J. Landis Martin J. Landis Martin	Director
* Jeffrey A. Miller Jeffrey A. Miller	President and Director
* Debra L. Reed Debra L. Reed	Director

/s/ Christina M. Ibrahim
*By Christina M. Ibrahim, Attorney-in-fact