BAKER HUGHES

2013 ANNUAL REPORT

2013 Year in Review

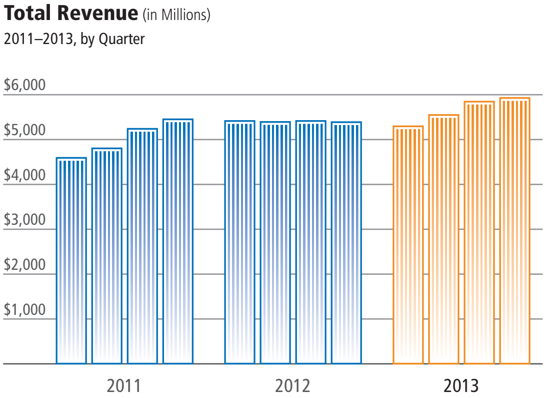
Culture of INNOV

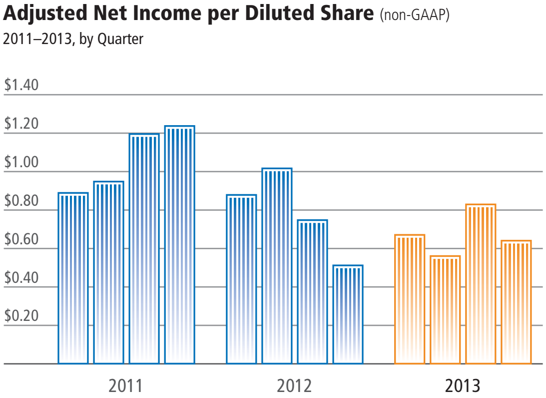
SOURCES OF INNOVATION

Innovation at Baker Hughes comes from many sources. It comes from listening to our customers and focusing intensely on understanding their challenges. It comes from imagination and vision that not only define success, but also create a roadmap and a timeline to achieve it, distribute ownership, and foster alignment among everyone involved.

Innovation comes from diversity—of culture, gender, age, point of view, academic background, discipline, and expertise. It is this diversity that creates the platform for challenging and questioning the past and the present.

We foster the diversity that nurtures innovation through numerous practices and programs that range from university recruitment and a special employment program for people leaving the U.S. Military forces, to our global Women's Resource Group and our annual Chad Deaton Diversity and Inclusion Award for helping to recruit, retain, and develop our talented and diverse workforce.





ATION

At Baker Hughes, our culture—that is, the behaviors and beliefs that define us as a company—is one of innovation. It is the foundation upon which the company was built and is the driving force behind our continuing leadership in oilfield services. We are guided by transforming ideas and inventions into commercial products and services that help make energy safe and affordable while improving the return on investment for our customers and investors, and improving the lives of the people we touch.

2013 Global Highlights

The first Blue Wellbore in Canada is the result of a turnkey commercial agreement that integrates five Baker Hughes product lines—Drilling Services, Drill Bits, Cementing, Wireline Services, and Completion Systems—and Baker Hughes field-based supervision.

Rhino™ Bifuel pump technology enabled a client in the Marcellus Shale to complete a large hydraulic fracturing operation using its own readily available field gas, reducing emissions and costly fuel shipments.

In the Norwegian North Sea, our SureTrak™ steerable drilling liner service—the industry's first—saved time and significantly increased recovery in a complex 3D well by allowing Statoil to drill, evaluate, and place a liner to total depth in a single run.

Our electrical submersible pumps were critical to enabling production from the world's first ice-resistant stationary platform in Arctic waters to enabling simultaneous oil production and water injection in the same wellbore in the Volga-Urals region.

In Japan, we played a crucial role in the development of the world's first successful marine methane hydrate production test.

The Gulf of Mexico's first high-pressure, intelligent well system saved millions of dollars for an operator working in 8,211 feet of water and established its value for future ultra-deepwater applications.

The first horizontal well drilled with the AutoTrak™ Curve rotary-steerable system reduced drilling time from an average of four days for one well to less than one day.

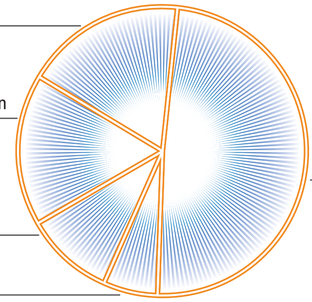
Our Dhahran Research and Technology Center in Saudi Arabia and the Reservoir Development Services Middle East Technology Center in Abu Dhabi will help Baker Hughes and our customers to better understand and more efficiently develop shale and tight gas in the Middle East.

Using a single Kymera™ hybrid drill bit to replace six conventional diamond bits on a high-profile land well resulted in a dramatic improvement in rate of penetration and saved 16 days of rig time.

Baker Hughes is using coiled tubing drilling and other innovative solutions to economically maximize ultimate recovery, improve revenue, and extend the life of mature fields in Malaysia.

A customer saved an estimated USD 10 million in rig days and operational efficiencies by using our FASTrak™ logging-while-drilling formation pressure testing and fluid sampling service.

2013 Revenue by Segment



Culture of INNOVATION

ENABLING INNOVATION

Innovation both creates and is enabled by a work environment that supports it. At Baker Hughes, we continually strive toward a work environment that motivates and empowers our employees, business partners, and customers to create new solutions and to evolve and perfect those that already exist. Our Dhahran Research and Technology Center in Saudi Arabia, our Artificial Lift Research and Technology Center in Oklahoma and our new Western Hemisphere Education Center in Houston are excellent examples of facilities as enablers. Here, leading-edge tools, testing facilities, and simulators enable ideas to be challenged and verified in a protected laboratory environment and then fine-tuned so they can be rapidly commercialized with confidence that they will perform as designed. Here, too, people from different disciplines, different geographies, and different companies can collaborate to achieve common objectives. And, it is here that engineers and scientists come together to learn from one another and from experts in all facets of oil and natural gas development.

THE RESULTS

The results of innovation at Baker Hughes are reflected in game-changing products and services and in business processes that encourage efficiency, collaboration, and future innovation. The latest results of our Culture of Innovation are highlighted in the following pages of this report and are already contributing to safer, more efficient, and more cost-effective exploration and production operations. The results of our innovations can be seen in the advancements we have brought to the oil and gas industry for more than a century. Today, we continue to introduce new products and services that will populate tomorrow's record books for enhancements in efficiency, economy, safety, and productivity and continue to enable safe, affordable energy to improve people's lives.

Selected Financial Highlights

(In millions, except per share amounts)	Year Ended December 31 2013	2012	2011	2010(1)	2009(1)
As Reported:					
Revenue	**$ 22,364**	$ 21,361	$ 19,831	$ 14,414	$ 9,664
Operating income	**1,949**	2,192	2,600	1,417	732
Net income	**1,103**	1,317	1,743	819	421
Net income attributable to Baker Hughes	**1,096**	1,311	1,739	812	421
Per share of common stock:					
Net income attributable to Baker Hughes:					
Basic	**$ 2.47**	$ 2.98	$ 3.99	$ 2.06	$ 1.36
Diluted	**2.47**	2.97	3.97	2.06	1.36
Dividends	**0.60**	0.60	0.60	0.60	0.60
Number of shares:					
Weighted average common shares diluted	**444**	441	438	395	311
Reconciliation from As Reported to Adjusted Net Income:					
Net income attributable to Baker Hughes	**$ 1,096**	$ 1,311	$ 1,739	$ 812	$ 421
Impairment of trade names(2)	**–**	–	220	–	–
Expenses related to Libya(3)	**–**	–	70	–	–
Loss on early extinguishment of debt(4)	**–**	–	26	–	–
Tax benefit associated with reorganization(5)	**–**	–	(214)	–	–
Information technology charges(6)	**–**	28	–	–	–
Facility closure(7)	**–**	15	–	–	–
Devaluation of Venezuelan currency(8)	**23**	–	–	–	–
Severance charges(9)	**46**	–	–	–	–
Adjusted net income(10)	**$ 1,165**	$ 1,354	$ 1,841	$ 812	$ 421
Per share of common stock:					
Adjusted net income(10):					
Basic	**$ 2.62**	$ 3.08	$ 4.22	$ 2.06	$ 1.36
Diluted	**2.62**	3.07	4.20	2.06	1.36
Cash, cash equivalents, and short-term investments	**$ 1,399**	$ 1,015	$ 1,050	$ 1,706	$ 1,595
Working capital	**6,717**	6,293	6,295	5,568	4,612
Total assets	**27,934**	26,689	24,847	22,986	11,439
Total debt	**4,381**	4,916	4,069	3,885	1,800
Equity	**17,912**	17,268	15,964	14,286	7,284
Total debt/capitalization	**20%**	22%	20%	21%	20%
Number of employees (thousands)	**59.4**	58.8	57.7	53.1	34.4

(1) We acquired BJ Services Company on April 28, 2010, and its financial results from the date of acquisition are included in our results. 2010 and 2009 net income also include costs incurred by Baker Hughes related to the acquisition and integration of BJ Services.

(2) Charge of $315 million before-tax ($220 million after-tax), the majority of which relates to the noncash impairment associated with the decision to minimize the use of the BJ Services trade name as part of our overall branding strategy for Baker Hughes.

(3) Expenses of $70 million (before and after-tax) associated with increasing the allowance for doubtful accounts, and reserves for inventory and certain other assets as a result of civil unrest in Libya.

(4) Loss of $40 million before-tax ($26 million after-tax) related to the early extinguishment in the third quarter of 2011 of $500 million notes due 2013.

(5) Noncash tax benefit of $214 million associated with the reorganization of certain foreign subsidiaries.

(6) Expenses of $43 million before-tax ($28 million after-tax) related to internally developed software and other information technology assets.

(7) Expenses of $20 million before-tax ($15 million after-tax) resulting from the closure of a chemical manufacturing facility in the United Kingdom.

(8) Foreign exchange loss of $23 million before and after-tax due to the devaluation of Venezuela's currency from the prior exchange rate of 4.3 Bolivars Fuertes per U.S. Dollar to 6.3 Bolivars Fuertes per U.S. Dollar, which applied to our local currency denominated balances.

(9) Severance charges of $56 million before-tax ($46 million after-tax).

(10) Adjusted net income is a non-GAAP measure comprised of net income attributable to Baker Hughes excluding the impact of certain identified items. The Company believes that adjusted net income is useful to investors because it is a consistent measure of the underlying results of the Company's business. Furthermore, management uses adjusted net income as a measure of the performance of the Company's operations.

Letter to Stockholders


Martin Craighead
Chairman and Chief Executive Officer

Baker Hughes delivered 2013 record revenue of $22.4 billion along with the highest free cash flow levels in the history of the company—a strong performance that was due to collaboration with our customers and a commitment to improving our business. We were awarded significant contracts in our international markets, particularly in the North Sea, and undertook field development projects in both hemispheres. We witnessed a growing appetite for our new technology from customers in the Middle East and Asia Pacific, and continued to transition to a service-based business model in Russia Caspian. And the initiatives we undertook to transform our U.S. Pressure Pumping business and to stabilize a volatile Latin America region showed steady progress.

At the heart of our 2013 performance was Baker Hughes technology. Throughout the year, we launched 129 products, combined products and services to create greater value for customers, and expanded our portfolio through a key alliance—continuing the innovation that is fundamental to the company's legacy and is the mainstay of our culture.

Twenty thirteen was a year of building momentum for Baker Hughes. The most prominent shift in our results came from a 24 percent growth in the Middle East/Asia Pacific region, which became our fastest-growing area and largest international segment. The Russia Caspian area reflected a strong demand for our reliable well construction solutions, and we continued to build critical mass in this market. In Latin America, the steps we took in the second half of the year to improve profits and reduce risk with a more stable business mix led to new contract wins in Colombia and Mexico. Our North America business continued to evolve, with our strategy to realign our Pressure Pumping business gaining traction. Although this business is improving, I was disappointed with the pace of its recovery, and I remain personally committed to correcting this performance during 2014.

Our Drill Bits, Drilling Services, Upstream Chemicals, Artificial Lift, and Completions Services product lines all performed exceptionally well in 2013, leveraging innovative new products to enhance shale production and unlock new and stranded reserves offshore.

While we exceeded several of our health, safety, and environment metrics during the year, our success was overshadowed by the loss of six employees in workplace incidents. These fatalities strengthened our resolve to be the undisputed leader in safety, sustainability, and compliance, and we continued to invest in the infrastructure to support safe and environmentally responsible operations. We broke ground for our Western Hemisphere Training Center near Houston, with an expected opening date of early 2014, and opened key new fluids and chemicals laboratories for the Gulf of Mexico.

Our $556-million investment in research and technology funded incremental developments, as well as game-changing ideas based on nontraditional oilfield science such as advanced materials and nanotechnology. And at the end of the year, our Oklahoma-based Artificial Lift Research and Technology Center—built to deliver state-of-the-art testing capabilities for production technology—was near completion.

"Increasingly, operators will seek technology solutions that not only improve efficiencies, but also help improve estimated ultimate recovery per well—and that will require a much deeper knowledge of the subsurface."

The investments we made in technology innovation were split generally among the market segments in which we have invested heavily for the past several years.

The deepwater segment, now expanding beyond its traditional boundaries into locations such as East Africa and the Red Sea, continued to exhibit low recovery rates—sometimes as little as 7 percent. One of the goals of the Lower Tertiary integrated project team we established in 2012 is to learn more about how to develop and produce these complex reservoirs so that we can design technology to boost production. In 2013, this team's work resulted in the world's first intelligent well system with a modified multizone, single-trip completion. Located in over 8,000 feet of water in the Cascade field, the well also featured the first high-pressure intelligent well system in the Gulf of Mexico.

In the challenging North Sea market, there is a demand for technology that economically captures remaining reserves. We collaborated with a major North Sea operator, whose chief challenge in mature assets was to recover stranded reserves in low-pressure zones, to develop the SureTrak™ steerable drilling liner service—the first technology of its kind, designed to drill and evaluate complex wells while simultaneously installing a liner. Unconventional operations also continued to expand outside North America, with Saudi Arabia and China being just two of several areas increasing their focus on shale. Certainly, we will apply our rich experience in North America to these emerging regions—but unconventional plays themselves have presented some other interesting new challenges.

The traditional focus on efficiency gains will soon not be enough to maintain the economics of unconventional wells. Increasingly, operators will seek technology solutions that help them improve estimated ultimate recovery per well—and that will require a much deeper knowledge of the subsurface than many operators have available. In 2013, we formed an alliance with CGG, a leading geophysical company, to integrate our near-wellbore data with the seismic data provided by CGG. This integration will enable full characterization of the reservoir throughout the life cycle of an unconventional well.

Pad drilling, an innovation that has driven efficiencies in unconventional plays, has redefined the way we look at drilling activity. For the last 70 years, the Baker Hughes Rig Count has been the industry's leading barometer of drilling activity. Today, because any number of wells can be drilled from one pad with one rig, a more accurate reflection of drilling activity is the number of wells, rather than the number of rigs. In the second quarter, we launched the Baker Hughes Well Count—a unique index that augments the Baker Hughes Rig Count to help the industry track and forecast U.S. activity in a more informed and comprehensive way.

In mature fields, Baker Hughes reservoir experts took innovative steps to help operators recover the estimated 65 percent of reserves that can potentially remain stranded in these assets. In Malaysia, the team conducted a two and a half-year field study focused on understanding a new block in a mature reservoir more intimately, so that previously bypassed reserves could be located and developed successfully. This study resulted in a multiyear mature field redevelopment project with Petronas Carigali in the offshore Greater D18 field. In Mexico, we won a multiyear contract with Pemex to optimize production and operational efficiency in the declining Soledad field. This project leverages our success in the neighboring Corralillo field, where we applied new technologies to triple production in less than four years.

All of these illustrations highlight the important role that Baker Hughes plays as a service provider—but I believe we have another, equally important, role as innovators. For Baker Hughes, innovation is both our heritage and the foundation for our future. It is the way we look at possibilities and determine how to make them realities. It is our differentiator.

"For Baker Hughes, innovation is both our heritage and the foundation for our future. It is the way we look at possibilities and determine how to make them realities."

Innovation without commercialization, however, is simply a science experiment. Several of our young technologies gained traction throughout 2013, demonstrating our ability to rapidly develop and commercialize technologies that significantly impact the market.

- The ground-breaking ProductionWave™ solution, delivered in a matter of months, improves reserve recovery in unconventional oil plays by combining the superior drawdown of our electrical submersible pumping (ESP) systems with products and services from our Completions Services and Upstream Chemicals product lines. Based on our FLEXPump™ series ESP technology, the *ProductionWave* solution offers a range of commercial models to meet the customer's unique business objectives.
- The SHADOW™ series frac plugs with disintegrating frac balls, also developed for the unconventionals market, extends the commercial application of our research in nanotechnology. *SHADOW* frac plugs eliminate the milling process in plug-and-perf completions. This technology was field-tested in 2013 and brought to market a year ahead of schedule.
- The AutoTrak™ Curve rotary steerable system, brought to market in 18 months, enables operators to improve drilling efficiencies in unconventional wells by drilling the vertical, curve, and horizontal sections in one run. The system enjoyed rapid customer adoption and quickly gained market share based on consistently reliable performance. In 2013, the system was on the precipice of drilling more than 10 million feet—less than two years after its launch.

Outlook

We are optimistic about the opportunities ahead for Baker Hughes. Indications are that 2014 will continue the positive trends that began in 2013. North America spending growth is expected to accelerate, and solid growth should continue in several international markets, particularly the Middle East, Africa, and Russia. Sustained strong oil prices, sanctioning of major projects, and delivery of a large number of offshore rigs are expected to drive spending increases among our customers.

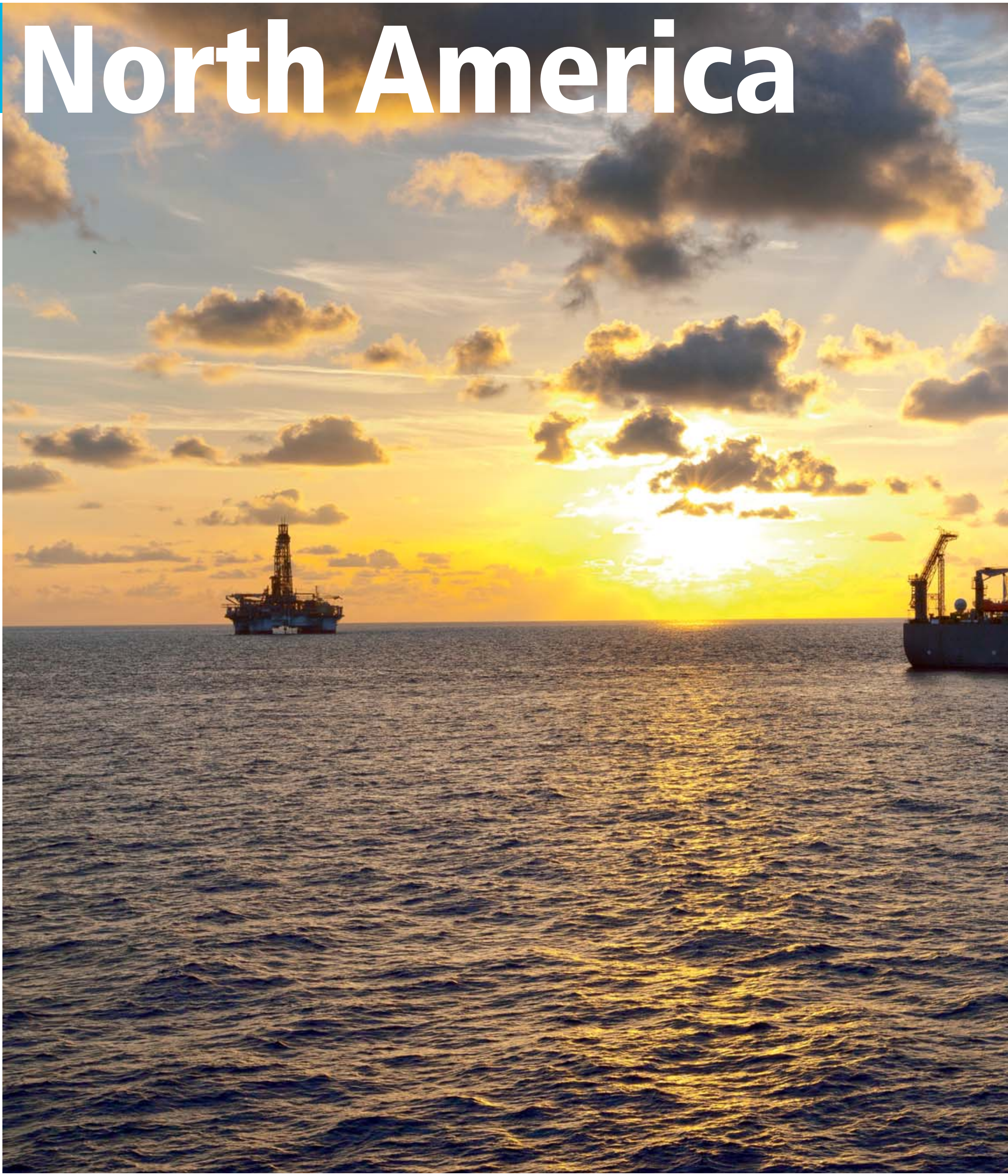
The year ahead also promises new prospects for our Chemical and Industrial Services business, with opportunities in deep water for Upstream Chemicals and a growing interest in industrial water treatment and petrochemical processing for Downstream Chemicals. We are particularly enthusiastic about the traction gained in the midstream market by the Process and Pipeline Services product line during 2013.

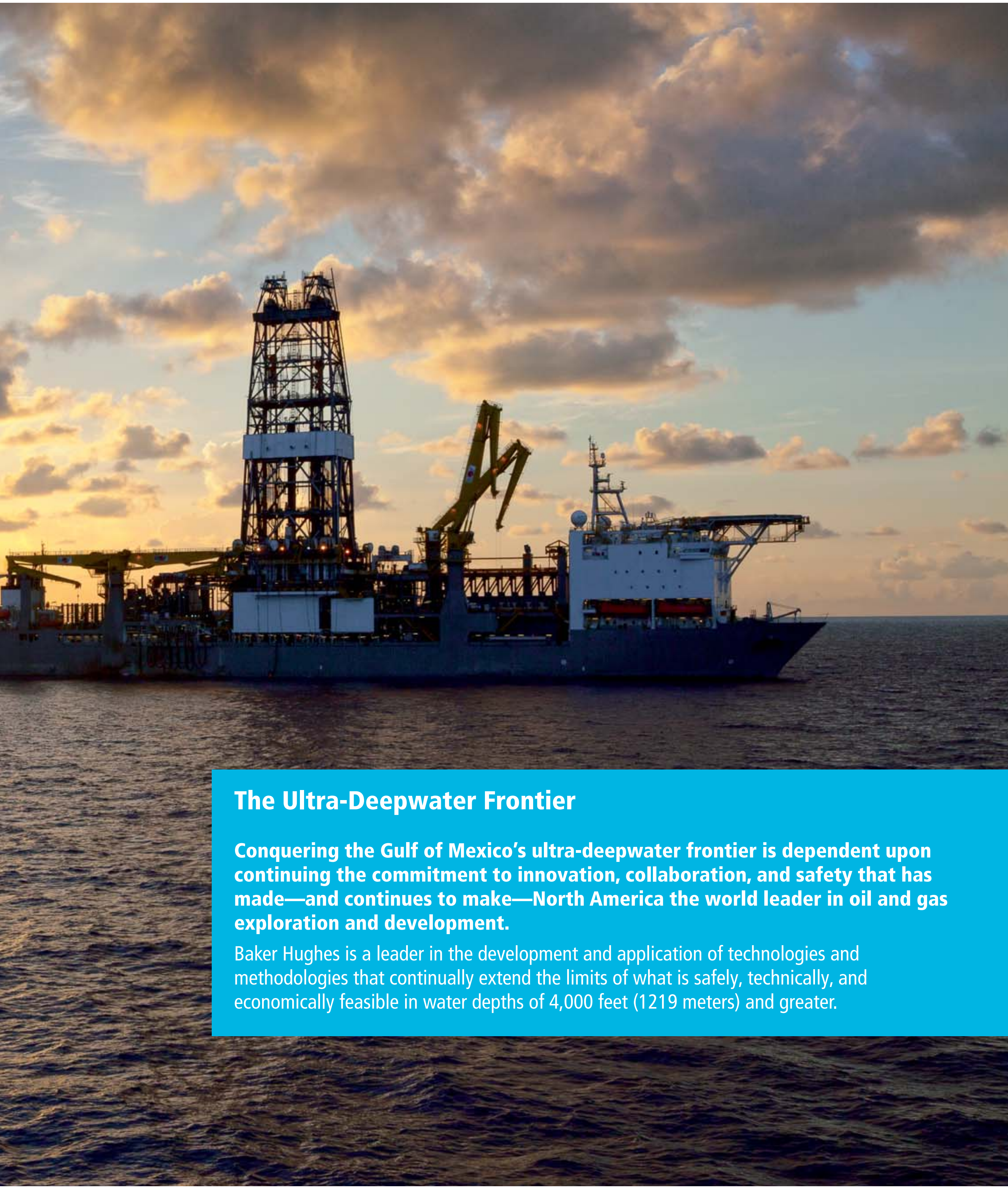
We are dedicated to meeting tomorrow's energy needs through innovations which simply do not exist today. We are committed to escalating technology development that meets the evolving challenges of our customers. Whether we are developing unconventional reservoirs, boosting production in mature fields, or navigating complex well geometries in ultra-deepwater fields, Baker Hughes will play a leading role in developing new ways to address these challenges.

You can be confident that Baker Hughes has the right capabilities, competencies, courage, and people to convert innovation into shareholder value.

Martin Craighead
Chairman and Chief Executive Officer

North America





The Ultra-Deepwater Frontier

Conquering the Gulf of Mexico's ultra-deepwater frontier is dependent upon continuing the commitment to innovation, collaboration, and safety that has made—and continues to make—North America the world leader in oil and gas exploration and development.

Baker Hughes is a leader in the development and application of technologies and methodologies that continually extend the limits of what is safely, technically, and economically feasible in water depths of 4,000 feet (1219 meters) and greater.

Innovative Results

North America

Our work in the Cascade and Chinook fields in the Gulf of Mexico's Lower Tertiary trend is an excellent example of our ultra-deepwater leadership.

We have been closely involved in the development of both fields since their inception, providing a wide range of directional drilling, evaluation, completions, and intervention services. In late 2013, we set a record in the Cascade field by installing the world's first intelligent well system (IWS) with a modified multizone, single-trip (MST) completion system in a water depth of 8,211 feet (2503 meters). The system was also the first high-pressure IWS in the Gulf of Mexico. It saved the operator millions of dollars, proving its value, not only for the remainder of the Chinook / Cascade project, but also as a key enabler of operating efficiencies and savings in future ultra-deepwater and high-pressure/high-temperature applications.

Extreme pressure and temperature combinations present an extreme challenge to ultra-deepwater operations. Baker Hughes and a major international oil company entered into a long-term research and development collaboration agreement in 2013 to develop completion technologies that will withstand temperatures approaching 500°F (260°C) and pressures of 30,000 psi (207 MPa) for very long periods of time. The first phase of the project involves identifying product designs, metallurgies, and sealing technologies that will withstand these conditions throughout a projected life span of 30 years.

"We set a record in the Cascade field by installing the world's first intelligent well system with a modified multizone, single-trip completion system in a water depth of 8,211 feet (2503 meters)."

The Blue Dolphin is the most capable offshore stimulation vessel in the Baker Hughes Gulf of Mexico fleet and the first in the industry to provide 20,000-psi (138 MPa) pressure pumping capability. The vessel recently completed an ultra-deepwater multizone fracturing completion in a single trip using the largest volume of proppant ever pumped into a gulf well.

Baker Hughes is a leader in bifuel hydraulic fracturing technology with its Rhino™ Bifuel pump fleets. The dual-fuel pumps reduce the use of diesel fuel by up to 70 percent and can operate twice as long as engines running solely on diesel. Safety is improved by eliminating refueling during pumping.

Reinforcing Performance, Compliance, and Consistency

Anticipating more stringent regulatory and contractual requirements governing safety, performance, and competency in the oilfield, Baker Hughes further expanded its International Association of Drilling Contractors- (IADC) accredited Competence Management Program (CMP) in 2013. The CMP provides a platform for human capital development across the enterprise and is supported by the Baker Hughes Operating System (BHOS), a digital document management system that enables global consistency of policies, processes, and procedures throughout the company.

Improving Shale Sustainability

North American shale reservoirs are abundant, often over large areas, but they are not homogeneous. Characteristics can vary considerably between reservoirs, wells, and even zones within wells. Comprehensive understanding of reservoir attributes, geomechanics, and stress regimes is necessary to effectively exploit the "sweet spots" in the reservoir. As the only service company with geoscience, hydraulic fracturing, artificial lift services, and production chemicals in its portfolio, Baker Hughes addresses shale play challenges from a uniquely sustainable perspective.

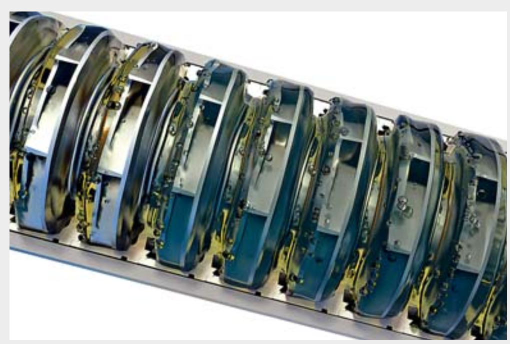
Baker Hughes is leading the shift to natural gas versus diesel fuel in hydraulic fracturing operations. In 2013, Cabot Oil & Gas Corporation employed our Rhino™ Bifuel pumps to hydraulically fracture 10 wells using a mixture of readily available field gas and diesel. Demonstrating peak efficiency, Baker Hughes completed all 10 wells in 28 days while replacing 110,000 gallons of costly diesel fuel with cleaner-burning natural gas from Cabot's nearby wells. The bifuel pumps also significantly lowered air emissions and related health, safety, and environmental (HSE) impact due to reduced truck traffic.

Using Baker Hughes SmartCare™ environmentally responsible chemical components further enhanced environmental protection.

Establishing New Benchmarks in Canada

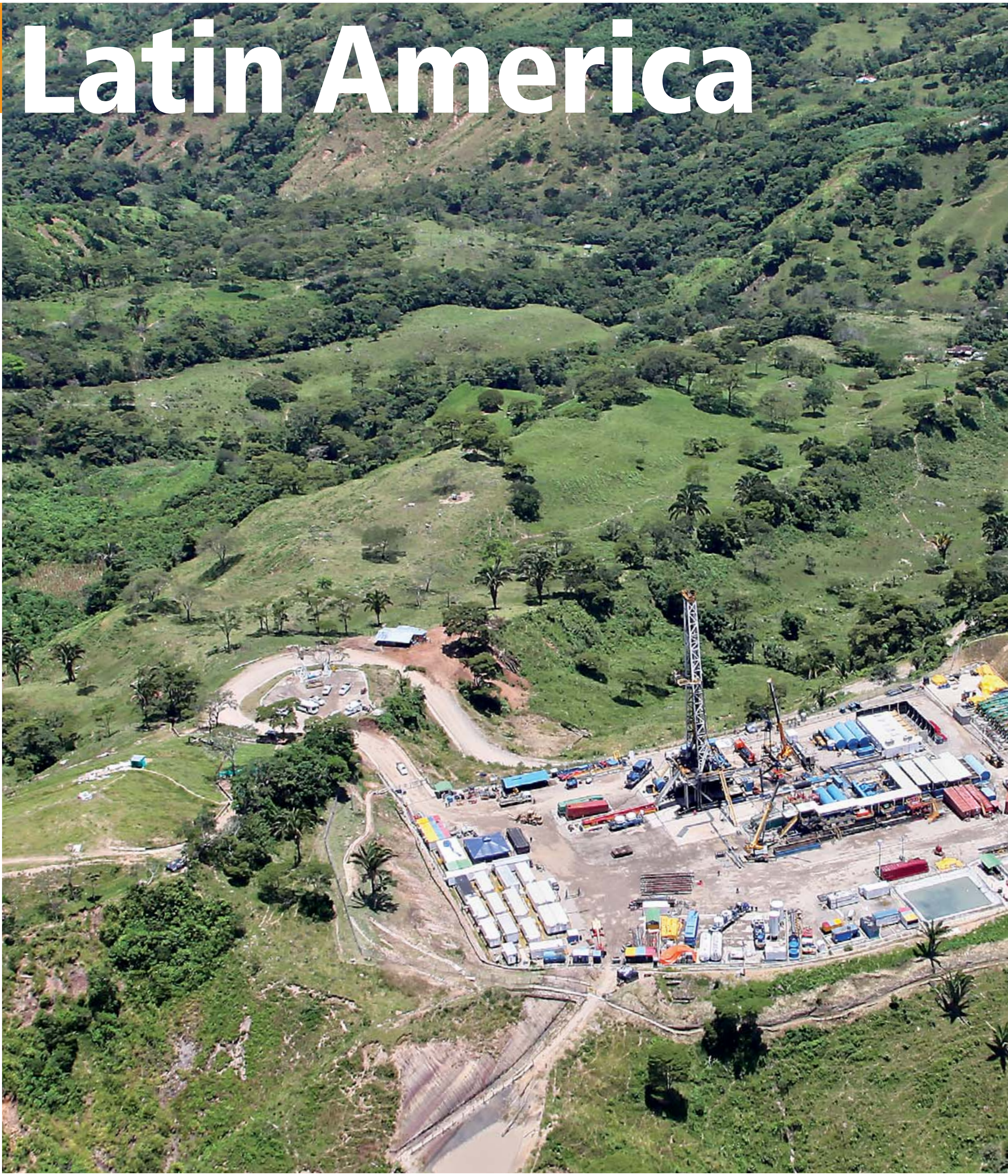
For Canadian operators seeking to unlock heavy oil reserves, Baker Hughes electrical submersible pumps (ESP) are setting new benchmarks for reliability and performance in steam-assisted gravity drainage (SAGD) operations. These CENtigrade™ ESP systems have exceeded customer run life targets, and should generate millions of dollars going forward by avoiding intervention costs and deferred production.

ProductionWave™ Solution Forges New Pathways



Unconventional oil wells typically have a steep decline curve and require artificial lift to maximize recovery. Rod-lift pumps are the traditional method of boosting production in low-flow-rate wells. Developed specifically for unconventional wells, the new Baker Hughes *ProductionWave* solution integrates artificial lift, production chemicals, sand screens, and remote real-time monitoring technologies. With this solution, operators will be able to increase production rates, even in low-flow-rate wells.

Latin America



Field Management

Slowing or reversing declining production from Latin America's mature fields requires creative application of leading-edge technology and innovative business models that change traditional working relationships between operators and service providers, to the mutual benefit of both.

Latin America

Operators in Mexico are beginning to award full-field management contracts for mature fields to qualified service providers such as Baker Hughes, who can provide resources and know-how to help accelerate production, add to the reserve base, and generate more revenues.

The Soledad project represents our first long-term, full-field management project in Mexico. The Soledad field management program will include optimizing production from existing oil-producing horizons as well as exploring for new production opportunities. For service companies like Baker Hughes, which historically have been contracted to construct and produce wells, managing an entire field—including facilities and environmental and community stewardship—presents exciting new opportunities, but also requires the skills and courage to take on responsibilities previously reserved for asset owners.

Collaborating to Innovate in the Andean Foothills

The Andean foothills in Colombia contain some of the world's most difficult onshore wells, with depths, deviations, and formation complexities that can push the boundaries of equipment, consume rig time, and elevate project costs. In 2013, Baker Hughes was awarded multiple contracts to provide well construction services for a major development campaign in the region.

Traditional well operations typically follow a sequential pattern in which the drilling team focuses on getting the well to total depth as fast as possible before handing it off to the completion and production team. Baker Hughes and the operator are addressing the interlinked challenges in the Andean foothills wells with a holistic approach in which all disciplines are collaborating to meet each other's technical needs and challenges. Following this approach, the integrated, multidiscipline teams are working together to define each problem; determine its impact, causes, and best solutions; and feed findings into a learning loop for continuous improvement going forward. This approach will significantly cut well construction time and cost from wells that, in some cases, currently cost up to USD 100 million and require almost a year to drill and complete.
In so doing, this hydrocarbon-rich area can become a significantly more valuable target for development.

Achieving break through performance in drilling and completing the deep, deviated, geologically complex wells of the Andean foothills will require innovative well designs and a collaborative, holistic approach—a perfect fit for Baker Hughes' portfolio of technologies and services.

"Powerful electrical submersible pump-based subsea boosting is becoming crucial to maximizing ultimate recovery in deep- and ultra-deepwater fields, such as Brazil."

Proving Nanotechnology in the Oilfield

The IN-Tallic™ frac balls that contributed to a hydraulic fracturing record in Argentina's Vaca Muerta field are composed of a groundbreaking nanostructured material developed by Baker Hughes. The material is lighter than aluminum yet stronger than some milled steels and has unique chemical properties that cause it to disintegrate when exposed to the appropriate fluid. *IN-Tallic* frac balls maintain their shape and strength during fracturing, then disintegrate at a controlled rate before or shortly after the well is put on production, so operators can achieve a more efficient fracturing operation and unimpeded production without the expense of removing the balls after a multistage completion.

Tapping the Vaca Muerta Shale

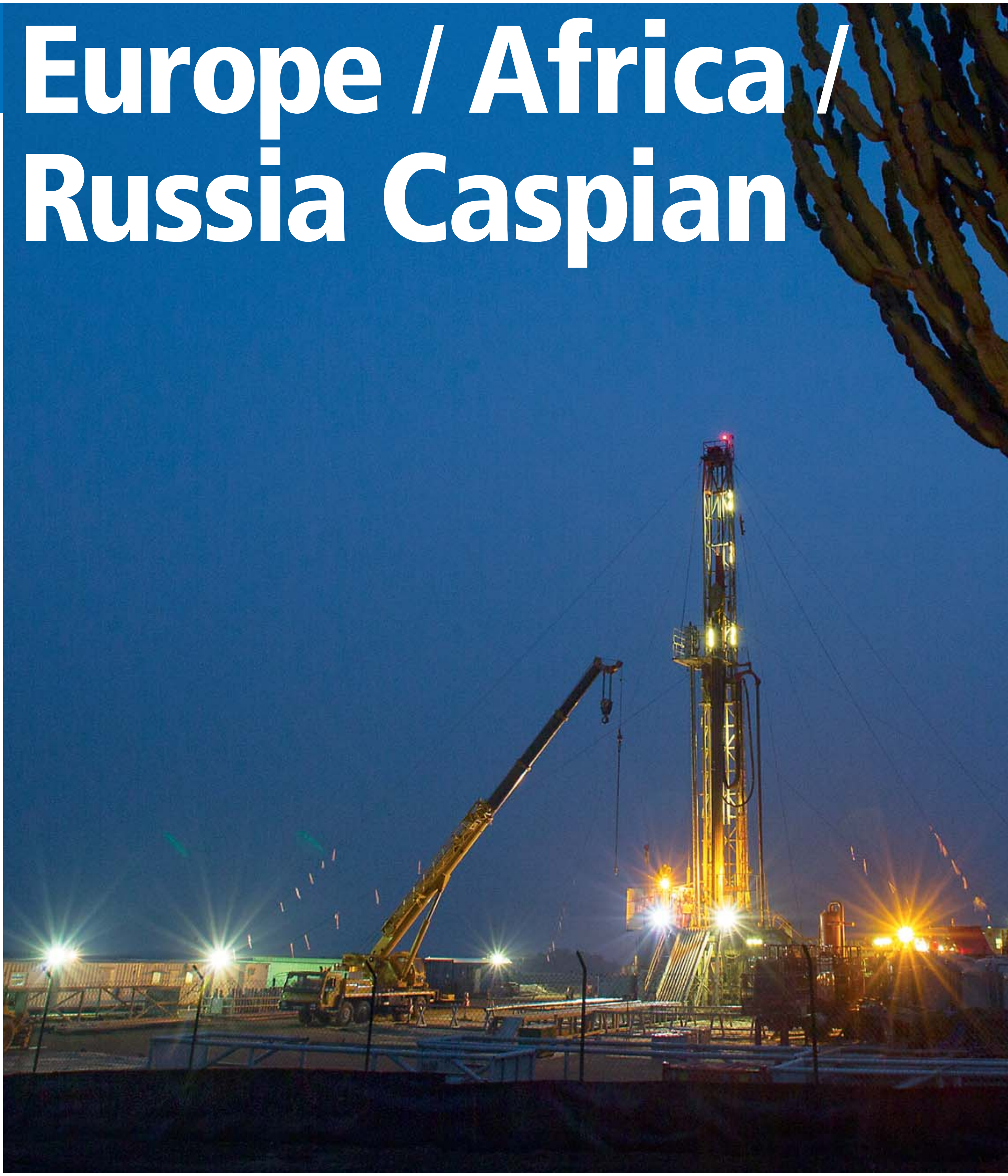
As unconventional resource development moves into Latin America, our reservoir expertise, well construction services and project management capabilities are in demand. Last November, we completed the first FracPoint™ multistage completion in South America, performing flawlessly to tap the Vaca Muerta shale play in Argentina. Using our IN-Tallic™ disintegrating frac balls, we set a record by hydraulically fracturing four of seven stages in one day.

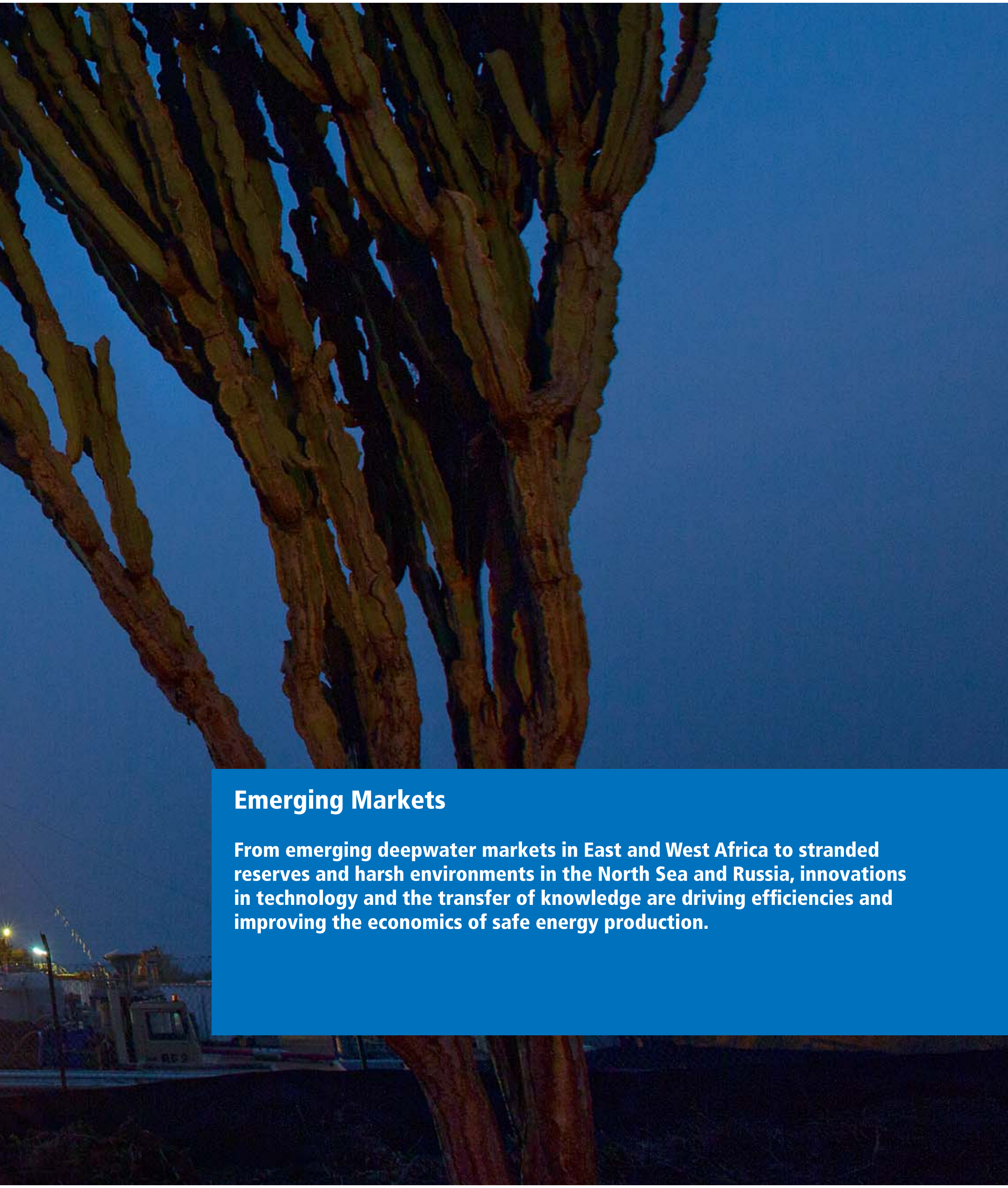
The flawless performance in the Vaca Muerta was the result of close collaboration between Baker Hughes and the operator. Customer personnel were immersed in our completion and pressure pumping technologies at our Center for Technology Innovation in Houston and at our pressure pumping technology facility in Tomball, Texas. Engineers from our Argentina team were trained in Oklahoma City, Oklahoma and Odessa, Texas, and the project was executed with help from field personnel from Mexico. The North America operations team supported the operation with engineering and equipment.

Boosting Production Offshore Brazil

Approximately one-half of the world's deepwater producing wells are between 5 and 10 years old and are reaching the point where intervention is necessary to rejuvenate production. At the same time, the reservoirs from which these wells produce are experiencing pressure depletion. Powerful ESP-based subsea boosting is becoming crucial to maximizing ultimate recovery in deep- and ultra-deepwater fields. Baker Hughes ESPs are key enablers of subsea separation and boosting of produced fluids. In Brazil, we installed the world's first horizontal subsea skid system, offshore in 3,930 feet (1200 meters) of water. The system's flawless performance and high production rates verified its asset-enhancing value.

Europe / Africa / Russia Caspian





Emerging Markets

From emerging deepwater markets in East and West Africa to stranded reserves and harsh environments in the North Sea and Russia, innovations in technology and the transfer of knowledge are driving efficiencies and improving the economics of safe energy production.

Europe / Africa / Russia Caspian

Photo courtesy of: Øyvind Hagen - Statoil ASA

Our growth in 2013 was largely driven by Eastern Hemisphere operations, particularly in areas where we are building critical mass in key markets—including Africa and Russia Caspian. And contracts underway and newly secured in the North Sea bolster our position in this important market.

Capital investment in the United Kingdom sector of the North Sea is at its highest level since the mid-1970s and is expected to continue at high levels for the near term. Similarly, a record number of fields are currently in operation on the Norwegian shelf, and 20 new discoveries were made in 2013. Baker Hughes has contributed to North Sea development since its inception, and our technological leadership here continues to grow.

Today, based on strong client relationships and technology, Baker Hughes is a leading provider of drilling services in the North Sea. Contributing to this accomplishment was the Baker Hughes Troll task force, whose work has enabled rates of penetration (ROP) in the Troll field to double since 2007 to dramatically increase reservoir exposure at a reduced cost. In 2013, we helped increase reservoir exposure from each wellhead in the field to a record-breaking 370,735 feet (113 000 meters).

We also secured the North Sea completions leadership position with the award of a major contract to provide cased-hole and IWS to improve well construction efficiency and contribute to long-term reservoir solutions in the majority of Statoil's North Sea fields.

Aiding Field Development in the United Kingdom

In the British sector, two complementary fluid analysis services—our wireline-based RCX™ Sentinel service, and our FASTrak™ logging-while-drilling (LWD) fluid analysis and sampling service—are aiding field development decision making and operational efficiency. The *RCX* service provides more accurate fluid analysis in one-quarter the time required by previous-generation sampling devices. The *FASTrak* service can capture and recover up to 16 fluid samples and collect an unlimited number of pressure and fluid analysis tests in real time to provide environmental, economic, time-saving, and data quality benefits over traditional methods of reservoir characterization.

Baker Hughes holds leadership positions in both drilling and completions in the North Sea, as a result of significant market share gains in 2013.

Major Advances for Russia Caspian

Challenges to oil and gas development in Russia include not only downhole operations, but also remote locations and harsh climates. In 2013, Baker Hughes played a significant role in two major Russian development projects.

In the first-ever Russian offshore Arctic development project, Baker Hughes helped the operator overcome numerous challenges to begin production from the

"Our Drilling Services in the North Sea have enabled ROP in the Troll field to double since 2007 to dramatically increase reservoir exposure at reduced cost."

Baker Hughes cased-hole completions systems, advanced ESP systems, and upstream chemical products are making it possible to produce oil in sufficient volumes to make Russia's offshore Arctic Prirazlomnoye field economically viable.

Prirazlomnaya, the world's first ice-resistant stationary oil platform in Arctic waters. The Prirazlomnoye field began producing oil in sufficient quantities to make the field economically viable after Baker Hughes installed cased-hole completions and production systems that included ESPs, packer systems, and advanced safety valves, and our upstream chemical products to produce the volumes of oil necessary to meet the project's economic parameters.

Baker Hughes completion and artificial lift systems also enabled the first dual-lift, concentric production-injection completion in Russia's Volga-Urals region. For this project, we designed the ESP system for the country's first successful attempt at simultaneous oil production and water injection in the same wellbore. The technology made it possible to inject water through the inner tubing string and produce oil from the outer string with no interference or commingling of fluids. Our continued participation in projects such as these will help to unlock Russia's harsh, remote environments.

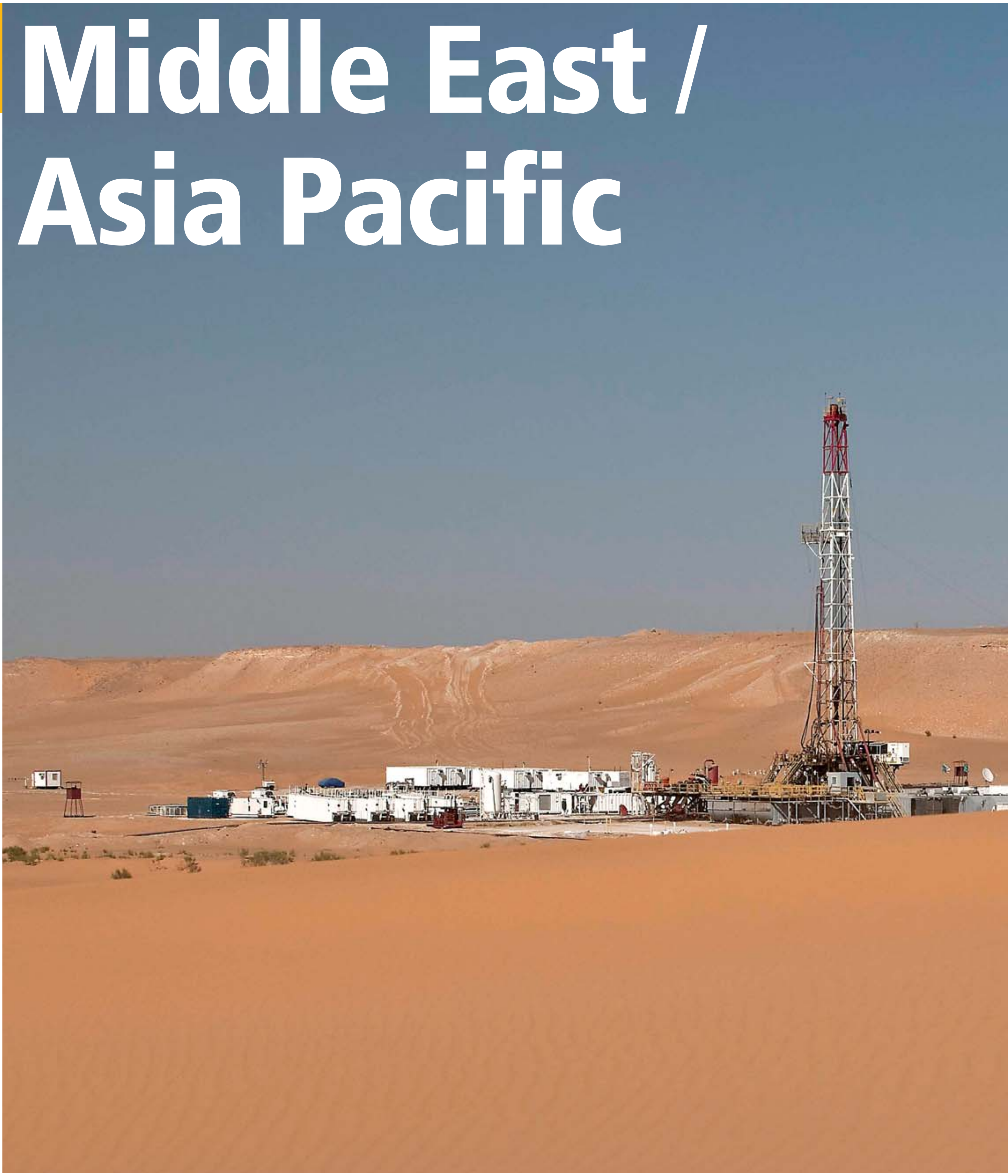
Investing in Africa

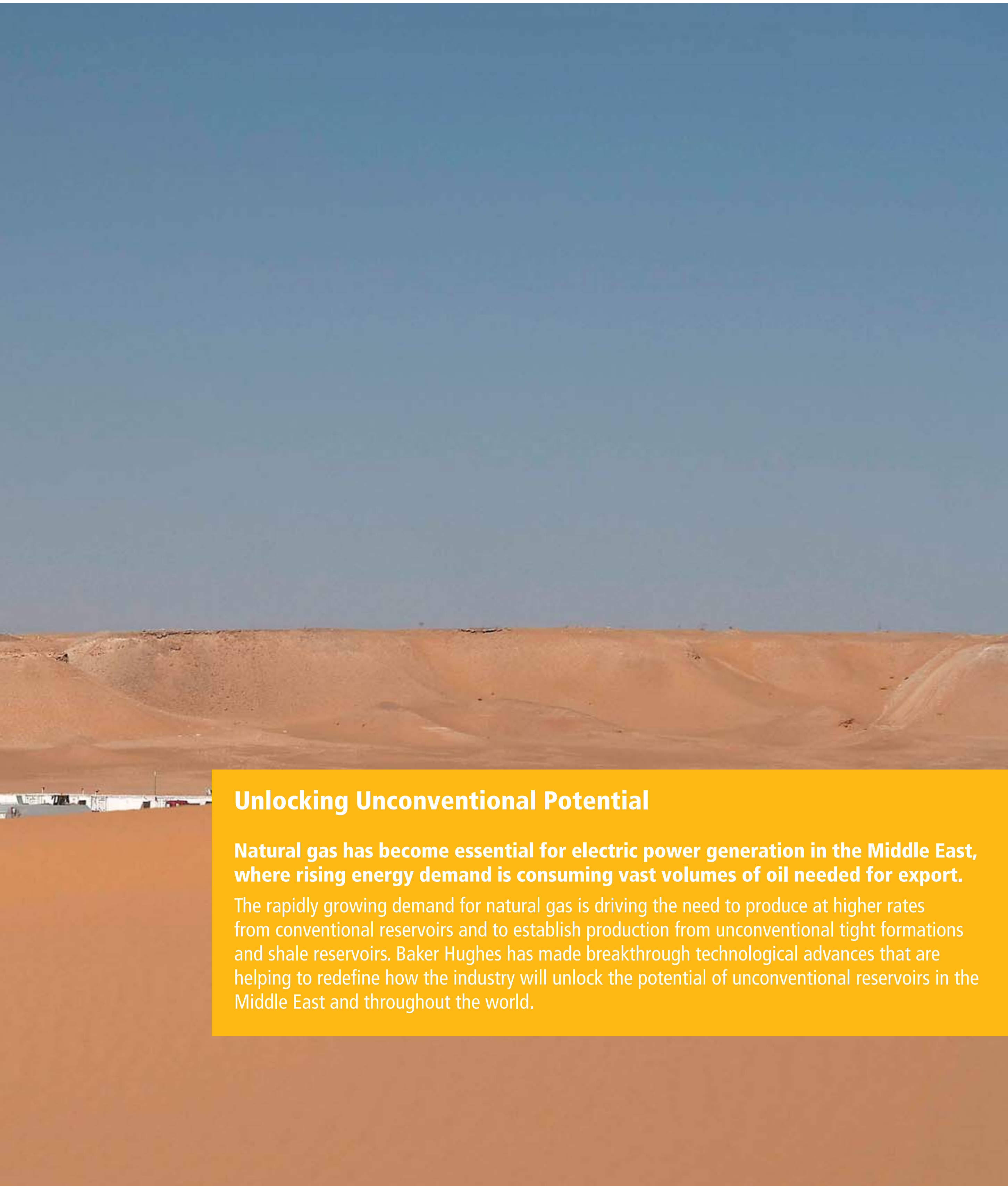
In East Africa, we have opened new facilities in the burgeoning markets of Kenya, Mozambique, and Tanzania. We are investing significant resources and working closely with major universities and business and engineering schools in the area. We also have implemented an orientation and assessment program as part of our recruitment process to offer young candidates the opportunity to meet and interact with professionals in their desired fields and to learn about the industry and position responsibilities. These efforts will help us achieve our 2015 target of a 95 percent national workforce in East Africa who will play a key role in developing their countries' hydrocarbon resources.

SureTrak™ Unlocks Stranded Reserves in the North Sea

The world's first application of the SureTrak™ steerable drilling liner technology enabled Statoil, the technology's codeveloper, to successfully drill through a trouble zone in the North Sea to reach a previously unreachable reservoir and dramatically increase oil recovery. *SureTrak* technology provides an alternative to more expensive methods, such as managed pressure drilling, to drill and complete wells through trouble zones. Unlike other liner and casing while drilling services, this drilling liner does not require special rig modifications, so pipe handling and nonproductive time are reduced. It is estimated that using the *SureTrak* technology could increase recovery by up to 1 million barrels per well.

Middle East / Asia Pacific





Unlocking Unconventional Potential

Natural gas has become essential for electric power generation in the Middle East, where rising energy demand is consuming vast volumes of oil needed for export.

The rapidly growing demand for natural gas is driving the need to produce at higher rates from conventional reservoirs and to establish production from unconventional tight formations and shale reservoirs. Baker Hughes has made breakthrough technological advances that are helping to redefine how the industry will unlock the potential of unconventional reservoirs in the Middle East and throughout the world.

Middle East / Asia Pacific

We have established an integrated, multidisciplinary approach to understanding and analyzing unconventional reserves that enables us to model and predict how reservoirs will perform.

We offer one of the industry's widest range of technical solutions that allow multistage hydraulic fracturing completions to be tailored to the reservoir, enhancing well productivity, and improving cost effectiveness. We also have contributed to advancements in reservoir evaluation, well pad location, and water management techniques that will help to lower unconventional development cost and optimize initial production rates and ultimate recovery. And, we are developing new ways to extract unconventional reserves by developing and incorporating nanotechnologies into various drilling, evaluation, hydraulic fracturing, and water management systems.

Focusing on the Reservoir

While many of the unconventional formations in the Middle East have been identified, their hydrocarbon potential and associated economics are uncertain. Baker Hughes has established two major centers—the Dhahran Research and Technology Center (DRTC) in Saudi Arabia and the Reservoir Development Services (RDS) Reservoir Consulting Center of Excellence in Abu Dhabi—as part of our commitment to improving the understanding and development of shale and tight gas reservoirs in the region. These centers provide a collaborative, innovative work environment for scientists and researchers to gain a better understanding of unconventional reservoirs that will ultimately enhance completion and stimulation designs.

Reservoir consulting teams based at the DRTC, the Abu Dhabi RDS technology center, and in clients' offices use our JewelSuite™ reservoir modeling software to provide operators with a comprehensive view of their reservoirs and to shorten building times for highly accurate reservoir models. The geomechanical test capability at the DRTC will help optimize drilling and hydraulic fracturing programs.

Managing Mature Fields

For mature fields in the Middle East, where recovery of 35 to 37 percent of original oil in place is typical, an improvement of even one percent in the recovery factor could power the area for several years. Baker Hughes is making significant contributions to technological advancements and methodologies that are helping Middle East operators increase mature field reserves and accelerate production with minimal cost and risk. We gather and review the data required for sound decision making, then focus on project planning that encompasses reservoir engineering, infill and stimulation opportunities, completion optimization, and improved oil recovery (IOR) and enhanced oil recovery (EOR) techniques.

To access bypassed reserves and accelerate well delivery, we combine our AutoTrak™ family of rotary closed-loop steerable drilling systems with the latest in drill bit technology, such as the award-winning Kymera™ hybrid bit. Our SureTrak™ steerable drilling liner provides a less risky, cost-effective

"We have established two major centers—in Saudi Arabia and Abu Dhabi—as part of our commitment to improving the understanding and development of shale and tight gas reservoirs in the region."

FASTrak™ Formation Fluid Analysis and Sampling

Analysis of reservoir fluid properties provides a wealth of information that guides field development decisions. Baker Hughes' award-winning FASTrak™ LWD technology integrates downhole fluid analysis and sampling with formation pressure while drilling to deliver environmental, economic, time-saving, and data quality benefits over traditional wireline methods of fluid analysis and sampling—particularly during the initial assessment of a reservoir's commercial potential. Pressure testing while drilling also provides important information for safety and drilling optimization. During 2013, our *FASTrak* technology enabled operators in Australia, Vietnam, and the United Arab Emirates to make critical field development decisions while saving valuable rig days. Those successes will extend its value and application throughout the Middle East / Asia Pacific region in 2014 and beyond.

The Dhahran Research and Technology Center in Saudi Arabia has a dual mission—to be close to Middle East shale gas development activity, and to be a center for technology development and transfer to increase reservoir access and hydrocarbon recovery.

alternative to either standard or managed-pressure drilling methods to drill through trouble zones. The *FASTrak* high-definition LWD service eliminates inefficient fracturing and has been shown to increase production by up to 20 percent.

We also have made significant strides toward rigless solutions that increase production while reducing nonproductive time and related cost and risk. Advancements in this area range from intelligent, coiled tubing-deployed wireline technologies to our new Mastiff™ rigless intervention system.

Being able to diagnose, plan, and execute with a broad portfolio of technologies and services that can be tailored to meet specific needs will enable Baker Hughes to play a pivotal role in managing the Middle East's mature fields.

Mobilizing D18

In Malaysia, where declining production from mature fields presents a challenge to economic growth in the area, Baker Hughes has entered into a 23-year agreement with Petronas Carigali to revitalize the 30-year-old Greater D18 field. The agreement followed a 2½-year field development study during which we applied our reservoir evaluation capabilities to analyze the geology and reservoir attributes of the complex, compartmentalized, offshore field.

We have developed a comprehensive field development plan to enhance existing production by identifying new targets and efficiently constructing new wells. Among fit-for-purpose technologies that will be implemented in the field is coiled tubing drilling (CTD). CTD will make it possible to access new and/or previously bypassed pay zones in these depleted wells, or drill sidetracks from them—without a rig. We will use CTD and other innovative solutions to economically maximize ultimate recovery, improve revenue, and extend field life for our customers.

Sustainability

At Baker Hughes, we realize that we earn our license to operate, not only by helping our customers achieve their asset development goals, but also by being stewards of the environment and responsible members of the communities in which we live and work.

Baker Hughes continually looks for ways to support our primary social causes—health and education—along with ways to engage our employees' time and talents in these sustainability efforts. In 2013, Baker Hughes employees participated in a wide range of social initiatives that ranged from renovating a school for the deaf, to awarding scholarships to female engineering students in Ghana, to raising relief funds for victims of Typhoon Haiyan in the Phillippines.

And in Malaysia, we supported our customer's sustainability objectives by opening the Baker Hughes Petroleum Education Centre at Universiti Teknologi PETRONAS (UTP), along with scholarship awards.

We also recognize that by attracting, developing, and retaining a diverse talent pool, our employees will make better business decisions and the company will be a better partner with our stakeholders. In 2013, we implemented a new military recruiting program that allows us to tap into a diverse, dedicated, and highly skilled group of individuals who are transitioning from military service to civilian life. The goal of this program is to fill 15 percent of open positions in the United States with veterans.

Baker Hughes works collaboratively within the oil and gas industry and directly with customers to address common health, safety, and environmental (HSE) issues and emerging challenges through active engagement in various industry groups. This year, we hosted our annual engagement forum with oil and gas companies to advance the conversation and provide deeper, collective insight into driving HSE performance across the industry.

The safety of our employees, our customers, and our other business partners is our most important objective each and every day. At Baker Hughes, we aim to make every day a 'Perfect HSE Day'—that is, a day with no injuries, no accidents, and no harm to the environment. This year, we took an important next step toward reaching our goal by launching our *Life Rules!*, a new process to help us remain focused on critical hazards and risks.

To help protect our environment, we continue to focus on energy efficiency and water conservation to align with our sustainability strategy and commitment to manage the risks associated with climate change. Sustainability improvements in our products and services continued this year with the expansion of our Rhino™ Bifuel fleets of hydraulic fracturing units. These units can replace up to 70 percent of the diesel fuel with natural gas, reducing greenhouse gas emissions. In 2013, we converted nearly 100 pumps in our hydraulic fracturing fleet to enable natural gas use. Other advances include the further development of environmentally-preferred chemicals and new technologies that reduce the amount of fresh water required.

Our visible leadership team and the daily efforts of all our employees have helped Baker Hughes become a sustainable company—one that protects its people, its assets, the environment and the communities where we live and operate.

Baker Hughes was recognized for its 2013 sustainability initiatives and accomplishments by the following investment and media institutions.

Dow Jones Sustainability Index

For the second year, we were named a world sustainability leader and the industry leader in the Energy Equipment and Services sector.

Carbon Disclosure Project (CDP)

The rise of investor-led initiatives such as CDP reflects the growing interest in socially responsible investment. We were the highest-ranked oilfield service company for the area of energy efficiency and climate change.

Bloomberg ESG Disclosure Index

For the third year, we were the leader in the Energy sector of the Bloomberg environment, social and governance (ESG) index.

CR Magazine's Best Corporate Citizens

We were the highest-ranking service company in the Energy sector based on our overall sustainability performance.

Executive Leadership Team

(left to right) Belgacem Chariag; Art Soucy (seated); Mario Ruscev; Martin Craighead; Alan Crain; Peter Ragauss (seated); Derek Mathieson; Maria Borras; Khaled Nouh; Dmitry Kuzovenkov; Richard Williams (seated); Didier Charreton; Archana Deskus.

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013

OR

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

Commission file number 1-9397

Baker Hughes Incorporated
(Exact name of registrant as specified in its charter)

Delaware	**76-0207995**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2929 Allen Parkway, Suite 2100, Houston, Texas	**77019-2118**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(713) 439-8600**

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

Title of each class	Name of each exchange on which registered
Common Stock, $1 Par Value per Share	New York Stock Exchange
	SIX Swiss 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 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 website, 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. (Check one):

Large accelerated filer [X]	Accelerated filer [ ]	Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates as of the last business day of the registrant's most recently completed second fiscal quarter (based on the closing price on June 28, 2013 reported by the New York Stock Exchange) was approximately $20,378,655,000.

As of February 7, 2014, the registrant has outstanding 437,191,478 shares of common stock, $1 par value per share.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Definitive Proxy Statement for the 2014 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

Baker Hughes Incorporated

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PART I

ITEM 1. BUSINESS

Baker Hughes Incorporated is a Delaware corporation engaged in the oilfield services industry. As used herein, phrases such as “Baker Hughes,” “Company,” “we,” “our” and “us” intend to refer to Baker Hughes Incorporated and/or its subsidiaries. The use of these terms is not intended to connote any particular corporate status or relationships.

AVAILABILITY OF INFORMATION FOR STOCKHOLDERS

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 Securities Exchange Act of 1934, as amended (the “Exchange Act”), are made available free of charge on our Internet website at www.bakerhughes.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the Securities and Exchange Commission (the “SEC”). Information contained on or connected to our website is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing we make with the SEC.

We have a Business Code of Conduct to provide guidance to our directors, officers and employees on matters of business conduct and ethics, including compliance standards and procedures. We have also required our principal executive officer, principal financial officer and principal accounting officer to sign a Code of Ethical Conduct Certification.

Our Business Code of Conduct and Code of Ethical Conduct Certifications are available on the Investor Relations section of our website at www.bakerhughes.com. We will disclose on a current report on Form 8-K or on our website information about any amendment or waiver of these codes for our executive officers and directors. Waiver information disclosed on our website will remain on the website for at least 12 months after the initial disclosure of a waiver. Our Corporate Governance Guidelines and the charters of our Audit/Ethics Committee, Compensation Committee, Executive Committee, Finance Committee and Governance Committee are also available on the Investor Relations section of our website at www.bakerhughes.com. In addition, a copy of our Business Code of Conduct, Code of Ethical Conduct Certifications, Corporate Governance Guidelines and the charters of the committees referenced above are available in print at no cost to any stockholder who requests them by writing or telephoning us at the following address or telephone number:

Baker Hughes Incorporated
2929 Allen Parkway, Suite 2100
Houston, TX 77019-2118
Attention: Investor Relations
Telephone: (713) 439-8600

ABOUT BAKER HUGHES

Baker Hughes is a leading supplier of oilfield services, products, technology and systems to the worldwide oil and natural gas industry. We also provide industrial products and services to the downstream chemicals, and process and pipeline industries. Baker Hughes was formed as a corporation in April 1987 in connection with the combination of Baker International Corporation and Hughes Tool Company. We conduct our operations through subsidiaries, affiliates, ventures and alliances. We operate in more than 80 countries around the world and our corporate headquarters is in Houston, Texas. As of December 31, 2013, we had approximately 59,400 employees, of which approximately 58% work outside the United States (“U.S.”).

Our global oilfield operations are organized into a number of geomarket organizations, which are combined into and report to four region presidents, who in turn report to our chief executive officer. These regions form the basis of our four operating segments detailed below:

North America - headquartered in Houston, Texas

Latin America - headquartered in Houston, Texas

Europe/Africa/Russia Caspian - headquartered in London, England

Middle East/Asia Pacific - headquartered in Dubai, United Arab Emirates

Through the geographic organization, we have placed our management close to our customers, facilitating stronger customer relationships and allowing us to react quickly to local market conditions and customer needs. The geographic organization supports our oilfield operations and is responsible for sales, field operations and well site execution. In addition to the above, we have an Industrial Services segment, headquartered in Houston, Texas, which includes the downstream chemicals business and the process and pipeline services business.

Certain support operations are organized at the enterprise level and include the supply chain and product line technology organizations. The supply chain organization is responsible for the cost-effective procurement and manufacturing of our products as well as product quality and reliability. The product line technology organization is responsible for product development, technology and marketing of innovative and reliable solutions for our customers to advance their reservoir performance. The product line technology organization also facilitates cross-product line technology development, sales processes and integrated operations capabilities.

Further information about our segments is set forth in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 9 of the Notes to Consolidated Financial Statements in Item 8 herein.

PRODUCTS AND SERVICES

Oilfield Operations

We offer a full suite of products and services to our customers around the world. Our oilfield products and services fall into one of two categories, Drilling and Evaluation or Completion and Production. This classification is based on the two major phases of constructing an oil and/or natural gas well, the drilling phase and the completion phase, and how our products and services are utilized for each phase.

- **Drilling and Evaluation** products and services consist of the following:
  - **Drill Bits** - includes Tricone™, PDC or "diamond", and Kymera™ hybrid drill bits used for performance drilling, hole enlargement and coring.
  - **Drilling Services** - includes conventional and rotary steerable systems used to drill wells directionally and horizontally; measurement-while-drilling and logging-while-drilling systems used to perform reservoir navigation services; drilling optimization services; tools for coil tubing drilling and wellbore re-entry systems; coring drilling systems; and surface logging.
  - **Wireline Services** - includes tools for both open hole and cased hole well logging used to gather data to perform petrophysical and geophysical analysis; reservoir evaluation coring; casing perforation; fluid characterization; production logging; well integrity testing; pipe recovery; and seismic and microseismic services.
  - **Drilling and Completion Fluids** - includes emulsion and water-based drilling fluids systems; reservoir drill-in fluids; and fluids environmental services.

- **Completion and Production** products and services consist of the following:
  - **Completion Systems** - includes products and services used to control the flow of hydrocarbons within a wellbore including sand control systems; liner hangers; wellbore isolation; expandable tubulars; multilaterals; safety systems; packers and flow control; and tubing conveyed perforating.
  - **Wellbore Intervention** - includes products and services used in existing wellbores to improve their performance including thru-tubing fishing; thru-tubing inflatables; conventional fishing; casing exit systems; production injection packers; remedial and stimulation tools; and wellbore cleanup.
  - **Intelligent Production Systems** - includes products and services used to monitor and dynamically control the production from individual wells or fields including production decisions services; chemical injection services; well monitoring services; intelligent well systems; and artificial lift monitoring.
  - **Artificial Lift** - includes electric submersible pump systems; progressing cavity pump systems; gas lift systems; and surface horizontal pumping systems used to lift large volumes of oil and water when a reservoir is no longer able to flow on its own.
  - **Upstream Chemicals** - includes chemicals and chemical application systems to provide flow assurance, integrity management and production management for upstream hydrocarbon production.
  - **Pressure Pumping** - includes cementing, stimulation, including hydraulic fracturing, and coil tubing services used in the completion of new oil and natural gas wells and in remedial work on existing wells, both onshore and offshore. Hydraulic fracturing is the practice of pumping fluid through a wellbore at pressures and rates sufficient to crack rock in the target formation, extend the cracks, and leave behind a propping agent to keep the cracks open after pumping ceases. The purpose of the cracks is to provide a pathway that allows for the passage of hydrocarbons from the rock to the wellbore, thus improving the production of hydrocarbons to the surface.

We also provide dedicated project solutions to our customers through our Integrated Operations group. Integrated Operations is focused on the execution of projects that have one or more of the following attributes: project management, well site supervision, well construction, intervention, third party contractor management, procurement and rig management. Contracts for this business unit tend to be longer in duration, often spanning multiple years, and may include significant third party components to supplement the core products and services provided by us. By partnering with Integrated Operations, customers access a comprehensive business solution that leverages our technical expertise, relationships with third party and rig providers, and our industry leading technologies.

Additional information regarding our oilfield products and services can be found on the Company's website at www.bakerhughes.com. Our website also includes details of our hydraulic fracturing operations, including the chemical content of our fluids systems, our support of the Chemical Disclosure Registry at www.fracfocus.org, and information on our SmartCare™ qualified systems and products, which are intended to maximize performance while minimizing our impact on the community and environment.

Industrial Services

Industrial Services consists primarily of our downstream chemicals, and process and pipeline services businesses. Downstream chemicals provides products and services that help to increase refinery production, as well as improve plant safety and equipment reliability. Process and pipeline services works to improve efficiency and reduce downtime with inspection, pre-commissioning and commissioning of new and existing pipeline systems and process plants.

MARKETING, COMPETITION AND CONTRACTING

We market our products and services within our four geographic regions on a product line basis primarily through our own sales organizations. We ordinarily provide technical and advisory services to assist in our customers' use of our products and services. Stock points and service centers for our products and services are located in areas of drilling and production activity throughout the world.

Our primary competitors include the major diversified oilfield service companies such as Schlumberger, Halliburton and Weatherford International, where the breadth of service capabilities as well as competitive position of each product line are the keys to differentiation in the market. We also compete with other companies who may participate in only a few of the same product lines as us, for example, National Oilwell Varco, Ecolab, Newpark

Resources and FTS International. Our products and services are sold in highly competitive markets and revenue and earnings are affected by changes in commodity prices, fluctuations in the level of drilling, workover and completion activity in major markets, general economic conditions, foreign currency exchange fluctuations and governmental regulations. We believe that the principal competitive factors in our industries are product and service quality, reliability and availability, health, safety and environmental standards, technical proficiency and price.

Our customers include the large integrated major and super-major oil and natural gas companies, U.S. and international independent oil and natural gas companies and the national or state-owned oil companies. No single customer accounts for more than 10% of our business. While we may have contracts with customers that include multiple well projects and that may extend over a period of time ranging from two to four years, our services and products are generally provided on a well-by-well basis. Most contracts cover our pricing of the products and services, but do not necessarily establish an obligation to use our products and services.

We strive to negotiate the terms of our customer contracts consistent with what we consider to be best practices. The general industry practice is for oilfield service providers, like us, to be responsible for their own products and services and for our customers to retain liability for drilling and related operations. Consistent with this practice, we generally take responsibility for our own people and property while our customers, such as the operator of a well, take responsibility for their own people, property and all liabilities related to the well and subsurface operations, regardless of either party's negligence. In general, any material limitations on indemnifications to us from our customers in support of this allocation of responsibility arise only by applicable statutes.

Certain states such as Texas, Louisiana, Wyoming, and New Mexico have enacted oil and natural gas specific statutes that void any indemnity agreement that attempts to relieve a party from liability resulting from its own negligence ("anti-indemnity statutes"). These statutes can void the allocation of liability agreed to in a contract; however, both the Texas and Louisiana anti-indemnity statutes include important exclusions. The Louisiana statute does not apply to property damage, and the Texas statute allows mutual indemnity agreements that are supported by insurance and has exclusions, which include, among other things, loss or liability for property damage that results from pollution and the cost of well control events. We negotiate with our customers in the U.S. to include a choice of law provision adopting the law of a state that does not have an anti-indemnity statute because both Baker Hughes and our customers generally prefer to contract on the basis as we mutually agree. When this does not occur, we will generally use Texas law. With the exclusions contained in the Texas anti-indemnity statute, we are usually able to structure the contract such that the limitation on the indemnification obligations of the customer is limited and should not have a material impact on the terms of the contract. State law, laws or public policy in countries outside the U.S., or the negotiated terms of our agreement with the customer may also limit the customer's indemnity obligations in the event of the gross negligence or willful misconduct of a Company employee. The Company and the customer may also agree to other limitations on the customer's indemnity obligations in the contract.

The Company maintains a commercial general liability insurance policy program that covers against certain operating hazards, including product liability claims and personal injury claims, as well as certain limited environmental pollution claims for damage to a third party or its property arising out of contact with pollution for which the Company is liable, but clean up and well control costs are not covered by such program. All of the insurance policies purchased by the Company are subject to self-insured retention amounts for which we are responsible for payment, specific terms, conditions, limitations and exclusions. There can be no assurance that the nature and amount of Company insurance will be sufficient to fully indemnify us against liabilities related to our business.

RESEARCH AND DEVELOPMENT AND PATENTS

Our products and technology organization engages in research and development activities directed primarily toward the development of new products, processes and services, the improvement of existing products and services and the design of specialized products to meet specific customer needs. We have technology centers located in the U.S. (Claremore, Oklahoma; and several in Houston, Texas and surrounding areas), Germany (Celle), Brazil (Rio de Janeiro), Russia (Novosibirsk), and Saudi Arabia (Dhahran). For information regarding the amounts of research and development expense in each of the three years in the period ended December 31, 2013, see Note 1 of the Notes to Consolidated Financial Statements in Item 8 herein.

We have followed a policy of seeking patent and trademark protection in numerous countries and regions throughout the world for products and methods that appear to have commercial significance. We believe our patents and trademarks are adequate for the conduct of our business, and aggressively pursue protection of our patents against patent infringement worldwide. Additionally, the Company considers the quality and timely delivery of its products, the service it provides to its customers and the technical knowledge and skills of its personnel to be other important components of the portfolio of capabilities and assets supporting its ability to compete. No single patent or trademark is considered to be critical to our business.

SEASONALITY

Our operations can be affected by seasonal weather, which can temporarily affect the delivery and performance of our products and services, as well as customers' budgetary cycles. Examples of seasonal events which can impact our business include:

- The severity and duration of both the summer and the winter in North America can have a significant impact on activity levels. In Canada, the timing and duration of the spring thaw directly affects activity levels, which reach seasonal lows during the second quarter and build through the third and fourth quarters to a seasonal high in the first quarter.
- Hurricanes and typhoons can disrupt coastal and offshore drilling and production operations.
- Severe weather during the winter months normally results in reduced activity levels in the North Sea and Russia generally in the first quarter.
- Scheduled repair and maintenance of offshore facilities in the North Sea can reduce activity in the second and third quarters.
- Many of our international oilfield customers increase orders for certain products and services in the fourth quarter.
- Our Industrial Services segment typically experiences lower sales during the first and fourth quarters of the year due to the Northern Hemisphere winter.

RAW MATERIALS

We purchase various raw materials and component parts for use in manufacturing our products and delivering our services. The principal materials we purchase include, but are not limited to, steel alloys (including chromium and nickel), titanium, barite, beryllium, copper, lead, tungsten carbide, synthetic and natural diamonds, gels, sand and other proppants, printed circuit boards and other electronic components and hydrocarbon-based chemical feed stocks. These materials are generally available from multiple sources and may be subject to price volatility. While we generally do not experience significant or long-term shortages of these materials, we have from time to time experienced temporary shortages of particular raw materials. In addition, we normally do not carry inventories of such materials in excess of those reasonably required to meet our production schedules. We do not expect significant interruptions in the supply of raw materials, but there can be no assurance that there will be no price or supply issues over the long-term.

EMPLOYEES

As of December 31, 2013, we had approximately 59,400 employees, of which the majority are outside the U.S. Less than 10% of these employees are represented under collective bargaining agreements or similar-type labor arrangements. Based upon the geographic diversification of these employees, we believe any risk of loss from employee strikes or other collective actions would not be material to the conduct of our operations taken as a whole.

EXECUTIVE OFFICERS OF BAKER HUGHES INCORPORATED

The following table shows, as of February 12, 2014, the name of each of our executive officers, together with his or her age and all offices presently held. There are no family relationships among our executive officers.

Name	Age	
Martin S. Craighead	54	Chairman of the Board of Directors of the Company since April 2013 and Director since 2011. Chief Executive Officer of the Company since January 2012 and President since 2010. Chief Operating Officer from 2009 to 2012. Group President of Drilling and Evaluation from 2007 to 2009 and Vice President of the Company from 2005 until 2009. President of INTEQ from 2005 to 2007. President of Baker Atlas from February 2005 to August 2005. Employed by the Company in 1986.
Peter A. Ragauss	56	Senior Vice President and Chief Financial Officer of the Company since 2006. Segment Controller of Refining and Marketing for BP plc from 2003 to 2006. Mr. Ragauss joined BP plc in 1998 as Assistant to the Group Chief Executive until 2000 when he became Chief Executive Officer of Air BP. Vice President of Finance and Portfolio Management for Amoco Energy International immediately prior to its merger with BP in 1998. Vice President of Finance for El Paso Energy International from 1996 to 1998. Employed by the Company in 2006. Mr. Ragauss has announced he will retire by December 31, 2014.
Maria Borras	45	President, Latin America Region of the Company since October 2013. President, Europe Region from August 2011 to October 2013 and Vice President, Global Marketing from May 2009 to July 2011. Various positions within operations, product line management, and leadership roles from March 1994 to April 2009. Petroleum Engineer at Petrobras, Occidental de Colombia from 1990 to 1994. Employed by the Company in 1994.
Belgacem Chariag	51	President, Global Products and Services since October 2013 and Vice President of the Company since 2009. President, Eastern Hemisphere Operations from 2009 to 2013. Vice President/Director HSE of Schlumberger Limited from May 2008 to May 2009. President of Well Services, a Schlumberger product line, from 2006 to 2008. Vice President Strategic Marketing Oilfield Services for Europe, Africa and CIS of Schlumberger from 2004 to 2006. Various other positions at Schlumberger from 1989 to 2008. Employed by the Company in 2009.
Didier Charreton	50	Vice President, Human Resources of the Company since 2007. Group Human Resources Director of Coats Plc, a global company engaged in the sewing thread and needlecrafts industry, from 2002 to 2007. Business Development of ID Applications for Gemplus S.A., a global company in the Smart Card industry, from 2000 to 2001. Various human resources positions at Schlumberger from 1989 to 2000. Employed by the Company in 2007.
Alan R. Crain	62	Senior Vice President, Chief Legal and Governance Officer of the Company since 2013. Senior Vice President and General Counsel of the Company from 2007 to 2013. Vice President and General Counsel from 2000 to 2007. Executive Vice President, General Counsel and Secretary of Crown, Cork & Seal Company, Inc. from 1999 to 2000. Vice President and General Counsel from 1996 to 1999, and Assistant General Counsel from 1988 to 1996, of Union Texas Petroleum Holdings, Inc. Employed by the Company in 2000.
Archana Deskus	48	Vice President and Chief Information Officer of the Company since 2013. Vice President and Chief Information Officer for Ingersoll-Rand from 2011 to 2012. Senior Vice President and Chief Information Officer for Timex Group from 2007 to 2011. Vice President and Chief Information Officer for Carrier North America from 2003 to 2006. Employed by the Company in 2013.
Alan J. Keifer	59	Vice President and Controller of the Company since 1999. Western Hemisphere Controller of Baker Oil Tools from 1997 to 1999 and Director of Corporate Audit for the Company from 1990 to 1996. Employed by the Company in 1990.

Dmitry Kuzovenkov	41	Vice President, Health, Safety and Environment of the Company since May 2013. President, Russia and Caspian Region from 2009 to 2013. Vice President, Drilling and Evaluation from 2008 to 2009 and Director Sales and Business Development from 2007 to 2008. Various positions with Schlumberger from 1995 to 2007 including Technology Manager for Schlumberger Wireline from 2005 to 2007, Operations Manager Pressure Pumping for East Mediterranean Geomarket from 2004 to 2005 and Operations Manager Pressure Pumping for South Texas from 2002 to 2004. Employed by the Company in 2007.
William D. Marsh	51	Vice President and General Counsel of the Company since February 2013. Vice President-Legal for Western Hemisphere from May 2009 to February 2013. Various executive, legal and corporate roles within the Company from 1998 to 2009. Partner at Ballard Spahr LLP from 1997 to 1998. Employed by the Company in 1998.
Jay G. Martin	62	Vice President, Chief Compliance Officer and Senior Deputy General Counsel of the Company since 2004. Shareholder at Winstead Sechrest & Minick P.C. from 2001 to 2004. Partner, Phelps Dunbar from 2000 to 2001. Partner, Andrews & Kurth from 1996 to 2000. Employed by the Company in 2004.
Derek Mathieson	43	Vice President, Strategy and Corporate Development of the Company since October 2013. Vice President of the Company since December 2008 and President Western Hemisphere Operations from 2012 to 2013. President, Products and Technology from May 2009 to January 2012. Chief Technology and Marketing Officer of the Company from December 2008 to May 2009. Chief Executive Officer of WellDynamics, Inc. from May 2007 to November 2008. Vice President Business Development, Technology and Marketing of WellDynamics, Inc. from April 2006 to May 2007. Technology Director and Chief Technology Officer from January 2004 to April 2006. Employed by the Company in 2008.
Khaled Nouh	46	President, Middle East and Asia Pacific Region of the Company since October 2013. President, Middle East Region from 2009 to 2013. Vice President Integrated Project Management Middle East at Schlumberger from 2008 to 2009. Vice President Operations for Saudi Arabia-Kuwait-Bahrain and Pakistan Region at Schlumberger from 2004 to 2008. Vice President Libya Operations at Schlumberger from 2003 to 2004. Various other vice president, engineering and management positions at Schlumberger from 1994 to 2003. Employed by the Company in 2009.
Mario Ruscev	57	Vice President and Chief Technology Officer of the Company since August 2012. Chief Executive Officer of Geotech Seismic Services from January 2012 to August 2012. Chief Executive Officer of FormFactor from 2008 to 2010. Various positions at Schlumberger for 20 years. Employed by the Company in 2012.
Arthur L. Soucy	51	President, Europe, Africa and Russia Caspian Region of the Company since 2013. Vice President of the Company since April 2009 and President Global Products and Services from 2012 to 2013. Vice President Supply Chain of the Company from April 2009 to January 2012. Vice President, Global Supply Chain for Pratt and Whitney from 2007 to 2009. Sloan Fellows Program, Innovation and Global Leadership at Massachusetts Institute of Technology from 2006 to 2007. General Manager, Combustors, Augmenters and Nozzles of Pratt and Whitney from 2005 to 2006. Various managerial positions at Pratt and Whitney from 1995 to 2006. Employed by the Company in 2009.
Richard L. Williams	58	President, North America Region of the Company since October 2013. President, U.S. Region from November 2012 to October 2013 and President, Gulf of Mexico Region from 2009 to 2012. Various positions within the Company from 1975 to 2009 including President of Baker Hughes Drilling Fluids, Vice President of Global Operations for INTEQ, Vice President of Western Hemisphere Operations and Vice President of North America Operations for Baker Oil Tools. Employed by the Company in 1975.

ENVIRONMENTAL MATTERS

We are committed to the health and safety of people, protection of the environment and compliance with laws, regulations and our policies. Our past and present operations include activities that are subject to extensive domestic (including U.S. federal, state and local) and international regulations with regard to air and water quality and other environmental matters. We believe we are in substantial compliance with these regulations. Regulation in this area continues to evolve, and changes in standards of enforcement of existing regulations, as well as the enactment and enforcement of new legislation, may require us and our customers to modify, supplement or replace equipment or facilities or to change or discontinue present methods of operation. Our environmental compliance expenditures and our capital costs for environmental control equipment may change accordingly.

We are involved in voluntary remediation projects at some of our present and former manufacturing locations or other facilities, the majority of which relate to properties no longer actively used in operations. On rare occasions, remediation activities are conducted as specified by a government agency-issued consent decree or agreed order. Estimated remediation costs are accrued using currently available facts, existing environmental permits, technology and presently enacted laws and regulations. For sites where we are primarily responsible for the remediation, our cost estimates are developed based on internal evaluations and are not discounted. We record accruals when it is probable that we will be obligated to pay amounts for environmental site evaluation, remediation or related activities, and such amounts can be reasonably estimated. In general, we seek to accrue costs for the most likely scenario, where known. Accruals are recorded even if significant uncertainties exist over the ultimate cost of the remediation. Ongoing environmental compliance costs, such as obtaining environmental permits, installation of pollution control equipment and waste disposal, are expensed as incurred.

The Comprehensive Environmental Response, Compensation and Liability Act (known as “Superfund”) imposes liability for the release of a “hazardous substance” into the environment. Superfund liability is imposed without regard to fault, even if the waste disposal was in compliance with laws and regulations. The U.S. Environmental Protection Agency (the “EPA”) and appropriate state agencies supervise investigative and cleanup activities at Superfund sites. We have been identified as a potentially responsible party (“PRP”) in remedial activities related to various Superfund sites, and we accrue our share of the estimated remediation costs of the site based on the ratio of the estimated volume of waste we contributed to the site to the total volume of waste disposed at the site. PRPs in Superfund actions have joint and several liability for all costs of remediation. Accordingly, a PRP may be required to pay more than its proportional share of such costs. For some projects, it is not possible to quantify our ultimate exposure because the projects are either in the investigative or early remediation stage, or allocation information is not yet available. However, based upon current information, we do not believe that probable or reasonably possible expenditures in connection with the sites are likely to have a material adverse effect on our consolidated financial statements because we have recorded adequate reserves to cover the estimate we presently believe will be our ultimate liability in the matter. Further, other PRPs involved in the sites have substantial assets and may reasonably be expected to pay their share of the cost of remediation, and, in some circumstances, we have insurance coverage or contractual indemnities from third parties to cover a portion of the ultimate liability.

Based upon current information, we believe that our overall compliance with environmental regulations, including routine environmental compliance costs and capital expenditures for environmental control equipment, will not have a material adverse effect upon our capital expenditures, earnings or competitive position because we have either established adequate reserves or our cost for that compliance is not expected to be material to our consolidated financial statements. Our total accrual for environmental remediation is $34 million and $32 million, which includes accruals of $4 million and $4 million for the various Superfund sites, at December 31, 2013 and 2012, respectively.

We are subject to various other governmental proceedings and regulations, including foreign regulations, relating to environmental matters, but we do not believe that any of these matters are likely to have a material adverse effect on our consolidated financial statements. We continue to focus on reducing future environmental liabilities by maintaining appropriate company standards and improving our assurance programs.

ITEM 1A. RISK FACTORS

An investment in our common stock involves various risks. When considering an investment in Baker Hughes, one should carefully consider all of the risk factors described below, as well as other information included and incorporated by reference in this report. There may be additional risks, uncertainties and matters not listed below, that we are unaware of, or that we currently consider immaterial. Any of these may adversely affect our business, financial condition, results of operations and cash flows and, thus, the value of an investment in Baker Hughes.

Risk Factors Related to the Worldwide Oil and Natural Gas Industry

Our business is focused on providing products and services to the worldwide oil and natural gas industry; therefore, our risk factors include those factors that impact, either positively or negatively, the markets for oil and natural gas. Expenditures by our customers for exploration, development and production of oil and natural gas are based on their expectations of future hydrocarbon demand, the risks associated with developing the reserves, their ability to finance exploration for and development of reserves, and the future value of the reserves. Their evaluation of the future value is based, in part, on their expectations for global demand, global supply, spare productive capacity, inventory levels and other factors that influence oil and natural gas prices. The key risk factors we believe are currently influencing the worldwide oil and natural gas markets are discussed below.

Demand for oil and natural gas is subject to factors beyond our control, which may adversely affect our operating results. Changes in the global economy could impact our customers' spending levels and our revenue and operating results.

Demand for oil and natural gas, as well as the demand for our services, is highly correlated with global economic growth, and in particular by the economic growth of countries such as the U.S., India, China, and developing countries in Asia and the Middle East who are either significant users of oil and natural gas or whose economies are experiencing the most rapid economic growth compared to the global average. Weakness or deterioration of the global economy or credit markets or the continued or renewed European sovereign debt crisis could reduce our customers' spending levels and reduce our revenue and operating results. Incremental weakness in global economic activity, particularly in China, India, Europe, the Middle East and developing countries in Asia, will reduce demand for oil and natural gas and result in lower oil and natural gas prices. Incremental strength in global economic activity in such areas will create more demand for oil and natural gas and support higher oil and natural gas prices. In addition, demand for oil and natural gas could be impacted by environmental regulation, including cap and trade legislation, regulation of hydraulic fracturing, carbon taxes and the cost for carbon capture and sequestration related regulations.

Supply of oil and natural gas is subject to factors beyond our control, which may adversely affect our operating results.

Productive capacity for oil and natural gas is dependent on our customers' decisions to develop and produce oil and natural gas reserves and on the regulatory environment in which our customers and we operate. The ability to produce oil and natural gas can be affected by the number and productivity of new wells drilled and completed, as well as the rate of production and resulting depletion of existing wells. Advanced technologies, such as horizontal drilling and hydraulic fracturing, improve total recovery but also result in a more rapid production decline and may become subject to more stringent regulation in the future.

Access to prospects is also important to our customers and such access may be limited because host governments do not allow access to the reserves.

Government regulations and the costs incurred by oil and natural gas exploration companies to conform to and comply with government regulations may also limit the quantity of oil and natural gas that may be economically produced.

Supply can also be impacted by the degree to which individual Organization of Petroleum Exporting Countries ("OPEC") nations and other large oil and natural gas producing countries, including, but not limited to, Norway and Russia, are willing and able to control production and exports of oil, to decrease or increase supply and to support their targeted oil price while meeting their market share objectives. Any of these factors could affect the supply of oil and natural gas and could have a material effect on our results of operations.

Changes in spare productive capacity or inventory levels can be indicative of future customer spending to explore for and develop oil and natural gas which in turn influences the demand for our products and services.

Spare productive capacity and oil and natural gas storage inventory levels are an indicator of the relative balance between supply and demand. High or increasing storage or inventories generally indicate that supply is exceeding demand and that energy prices are likely to soften. Low or decreasing storage or inventories are an indicator that demand is growing faster than supply and that energy prices are likely to rise. Measures of maximum productive capacity compared to demand ("spare productive capacity") are also an important factor influencing energy prices and spending by oil and natural gas exploration companies. When spare productive capacity is low compared to demand, energy prices tend to be higher and more volatile, reflecting the increased vulnerability of the entire system to disruption.

Volatility of oil and natural gas prices can adversely affect demand for our products and services.

Volatility in oil and natural gas prices can also impact our customers' activity levels and spending for our products and services. Current energy prices are important contributors to cash flow for our customers and their ability to fund exploration and development activities. Expectations about future prices and price volatility are important for determining future spending levels.

Lower oil and natural gas prices generally lead to decreased spending by our customers. While higher oil and natural gas prices generally lead to increased spending by our customers, sustained high energy prices can be an impediment to economic growth, and can therefore negatively impact spending by our customers. Our customers also take into account the volatility of energy prices and other risk factors by requiring higher returns for individual projects if there is higher perceived risk. Any of these factors could affect the demand for oil and natural gas and could have a material effect on our results of operations.

Our customers' activity levels and spending for our products and services and ability to pay amounts owed us could be impacted by the ability of our customers to access equity or credit markets.

Our customers' access to capital is dependent on their ability to access the funds necessary to develop economically attractive projects based upon their expectations of future energy prices, required investments and resulting returns. Limited access to external sources of funding has and may continue to cause customers to reduce their capital spending plans to levels supported by internally-generated cash flow. In addition, a reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facilities or the lack of available debt or equity financing may impact the ability of our customers to pay amounts owed to us.

Seasonal and weather conditions could adversely affect demand for our services and operations.

Variation from normal weather patterns, such as cooler or warmer summers and winters, can have a significant impact on demand. Adverse weather conditions, such as hurricanes in the Gulf of Mexico, may interrupt or curtail our operations, or our customers' operations, cause supply disruptions and result in a loss of revenue and damage to our equipment and facilities, which may or may not be insured. Extreme winter conditions in Canada, Russia or the North Sea may interrupt or curtail our operations, or our customers' operations, in those areas and result in a loss of revenue.

Risk Factors Related to Our Business

Our expectations regarding our business are affected by the following risk factors and the timing of any of these risk factors:

We operate in a highly competitive environment, which may adversely affect our ability to succeed.

We operate in a highly competitive environment for marketing oilfield services and securing equipment and trained personnel. Our ability to continually provide competitive products and services can impact our ability to defend, maintain or increase prices for our products and services, maintain market share and negotiate acceptable contract terms with our customers. In order to be competitive, we must provide new technologies, reliable products and services that perform as expected and that create value for our customers, and successfully recruit, train and retain competent personnel. Our ability to defend, maintain or increase prices for our products and services is in part dependent on the industry's capacity relative to customer demand, and on our ability to differentiate the value delivered by our products and services from our competitors' products and services.

Managing development of competitive technology and new product introductions on a forecasted schedule and at forecasted costs can impact our financial results. Development of competing technology that accelerates the obsolescence of any of our products or services can have a detrimental impact on our financial results.

We may be disadvantaged competitively and financially by a significant movement of exploration and production operations to areas of the world in which we are not currently active.

The high cost or unavailability of infrastructure, materials, equipment, supplies and personnel, particularly in periods of rapid growth, could adversely affect our ability to execute our operations on a timely basis.

Our manufacturing operations are dependent on having sufficient raw materials, component parts and manufacturing capacity available to meet our manufacturing plans at a reasonable cost while minimizing inventories. Our ability to effectively manage our manufacturing operations and meet these goals can have an impact on our business, including our ability to meet our manufacturing plans and revenue goals, control costs, and avoid shortages of raw materials and component parts. Raw materials and components of particular concern include steel alloys (including chromium and nickel), titanium, barite, beryllium, copper, lead, tungsten carbide, synthetic and natural diamonds, gels, sand and other proppants, printed circuit boards and other electronic components and hydrocarbon-based chemical feed stocks. Our ability to repair or replace equipment damaged or lost in the well can also impact our ability to service our customers. A lack of manufacturing capacity could result in increased backlog, which may limit our ability to respond to orders with short lead times.

People are a key resource to developing, manufacturing and delivering our products and services to our customers around the world. Our ability to manage the recruiting, training, retention and efficient usage of the highly skilled workforce required by our plans and to manage the associated costs could impact our business. A well-trained, motivated workforce has a positive impact on our ability to attract and retain business. Periods of rapid growth present a challenge to us and our industry to recruit, train and retain our employees, while managing the impact of wage inflation and potential lack of available qualified labor in the markets where we operate. Likewise, when there is a downturn in the economy or our markets, we may have to adjust our workforce to control costs and yet not lose our skilled and diverse workforce. Labor-related actions, including strikes, slowdowns and facility occupations can also have a negative impact on our business.

Our business is subject to geopolitical and terrorism threats.

Geopolitical and terrorism risks continue to grow in a number of key countries where we do business. Geopolitical and terrorism risks could lead to, among other things, a loss of our investment in the country, impairment of the safety of our employees and impairment of our ability to conduct our operations.

Uncertainties in Venezuela have impacted our business operations.

We believe there are risks and uncertainties associated with our operations in Venezuela. We are not able to predict how these risks and uncertainties may impact collections of accounts receivable and our ability to continue operations. We continue to experience delays in receiving payments from our customers in Venezuela. As of December 31, 2013, our accounts receivable in Venezuela were approximately 2% of our total accounts receivable (net of related allowance for doubtful accounts). For the year ended December 31, 2013, revenue in Venezuela was approximately 1% of our total consolidated revenue. In addition, our operations could be impacted by any further devaluation of the local currency or other action of the Venezuelan government that impedes our ability to conduct operations, which could have a material adverse effect on our results of operations.

Our business is subject to cybersecurity risks and threats.

Threats to our information technology systems associated with cybersecurity risks and cyber incidents or attacks continue to grow. It is also possible that breaches to our systems could go unnoticed for some period of time. Risks associated with these threats include, among other things, loss of intellectual property, impairment of our ability to conduct our operations, disruption of our customers' operations, loss or damage to our customer data delivery systems, and increased costs to prevent, respond to or mitigate cybersecurity events.

Our failure to comply with the Foreign Corrupt Practices Act ("FCPA") would have a negative impact on our ongoing operations.

Our ability to comply with the FCPA is dependent on the success of our ongoing compliance program, including our ability to continue to manage our agents and business partners, and supervise, train and retain competent employees. Our compliance program is also dependent on the efforts of our employees to comply with applicable law and the Baker Hughes Business Code of Conduct. We could be subject to sanctions and civil and criminal prosecution as well as fines and penalties in the event of a finding of a violation of the FCPA by us or any of our employees.

Compliance with and changes in laws could be costly and could affect operating results. In addition, government disruptions could negatively impact our ability to conduct our business.

We have operations in the U.S. and in more than 80 countries that can be impacted by expected and unexpected changes in the legal and business environments in which we operate. Compliance related issues could also limit our ability to do business in certain countries and impact our earnings. Changes that could impact the legal environment include new legislation, new regulations, new policies, investigations and legal proceedings and new interpretations of existing legal rules and regulations, in particular, changes in export control laws or exchange control laws, additional restrictions on doing business in countries subject to sanctions, and changes in laws in countries where we operate or intend to operate. In addition, government disruptions, such as a U.S. government shutdown, may delay or halt the granting and renewal of permits, licenses and other items required by us and our customers to conduct our business.

Changes in tax laws or tax rates, adverse positions taken by taxing authorities and tax audits could impact operating results.

Changes in tax laws or tax rates, the resolution of tax assessments or audits by various tax authorities, and the ability to fully utilize our tax loss carryforwards and tax credits could impact operating results. In addition, we may periodically restructure our legal entity organization. If taxing authorities were to disagree with our tax positions in connection with any such restructurings, our effective tax rate could be materially impacted.

Our tax filings for various periods are subject to audit by the tax authorities in most jurisdictions where we conduct business. We have received tax assessments from various taxing authorities and are currently at varying stages of appeals and/or litigation regarding these matters. These audits may result in assessment of additional taxes that are resolved with the authorities or through the courts. We believe these assessments may occasionally be based on erroneous and even arbitrary interpretations of local tax law. Resolution of any tax matter involves uncertainties and there are no assurances that the outcomes will be favorable.

Changes in and compliance with restrictions or regulations on offshore drilling has and may continue to adversely affect our business and operating results and reduce the need for our services in those areas.

Legislation and regulation in the U.S. and other parts of the world of the offshore oil and natural gas industry may result in substantial increases in costs or delays in drilling or other operations in the Gulf of Mexico and other parts of the world, oil and natural gas projects becoming potentially non-economic, and a corresponding reduced demand for our services. If the U.S. or other countries where we operate, enact stricter restrictions on offshore drilling or further regulate offshore drilling or contracting services operations, higher operating costs could result and adversely affect our business and operating results.

If the Company were to be involved in a future incident similar to the 2010 Deepwater Horizon accident, the Company could suffer significant financial losses that could severely impair the Company. Protections available to the Company through contractual terms and insurance coverage may not be sufficient to protect the Company in the event we were involved in that type of an incident.

Compliance with, and rulings and litigation in connection with, environmental regulations and the environmental impacts of our or our customers' operations may adversely affect our business and operating results.

Our business is impacted by material changes in environmental laws, rulings and litigation. Our expectations regarding our compliance with environmental laws and our expenditures to comply with environmental laws, including (without limitation) our capital expenditures for environmental control equipment, are only our forecasts regarding these matters. These forecasts may be substantially different from actual results, which may be affected by factors such as: changes in law that impose new restrictions on air emissions, wastewater management, waste disposal, hydraulic fracturing, or wetland and land use practices; more stringent enforcement of existing environmental regulations; a change in our allocation or other unexpected, adverse outcomes with respect to sites where we have been named as a PRP, including (without limitation) Superfund sites; the discovery of other sites where additional expenditures may be required to comply with environmental legal obligations; and the accidental discharge of hazardous materials.

International, national, and state governments and agencies continue to evaluate and promulgate legislation and regulations that are focused on restricting emissions commonly referred to as greenhouse gas ("GHG") emissions. In the U.S., the EPA has taken steps to regulate GHGs as pollutants under the Clean Air Act. The EPA's "Mandatory Reporting of Greenhouse Gases" rule established in 2010 provided a comprehensive scheme of regulations that require monitoring and reporting of GHG emissions. Furthermore, the EPA has issued additional GHG reporting rules specifically for the oil and natural gas industry, which now include mobile as well as stationary GHG emission sources. These rules apply to our customers and may apply to some of our wellsite equipment and operations in the future.

International developments focused on restricting the emission of carbon dioxide and other gases include the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol" (an internationally applied protocol) and the European Union's Emission Trading System. The Carbon Reduction Commitment in the United Kingdom ("U.K.") is the first cap and trade scheme to affect Baker Hughes' facilities. Domestic cap and trade programs include the Regional Greenhouse Gas Initiative in the northeastern U.S. and the Western Regional Climate Action Initiative in the western U.S.

Current or future legislation, regulations and developments may curtail production and demand for hydrocarbons such as oil and natural gas in areas of the world where our customers operate and thus adversely affect future demand for our services, which may in turn adversely affect future results of operations.

Demand for pressure pumping services could be reduced or eliminated by governmental regulation or a change in the law.

Some federal, state and foreign governmental bodies have adopted laws and regulations or are considering legislative and regulatory proposals that, if signed into law, would among other things require the public disclosure of chemicals used in hydraulic fracturing operations and would subject hydraulic fracturing to more stringent regulation with respect to, for example, construction standards for wells intended for hydraulic fracturing, certifications concerning the conduct of hydraulic fracturing operations, management of flowback waters from hydraulic fracturing operations, or other measures intended to prevent operational hazards. Such federal, state or foreign legislation and/or regulations could impair our operations, increase our operating costs, and/or greatly reduce or eliminate demand for the Company's hydraulic fracturing services. The EPA and other governmental bodies are studying hydraulic fracturing operations. Government actions relating to the development of unconventional oil and natural gas resources may impede the development of these resources by our customers, delaying or reducing the demand for our services. We are unable to predict whether the proposed changes in laws or regulations or any other governmental proposals or responses will ultimately occur, and accordingly, we are unable to assess the potential financial or operational impact they may have on our business.

Uninsured claims and litigation against us could adversely impact our operating results.

We could be impacted by the outcome of pending litigation as well as unexpected litigation or proceedings. We have insurance coverage against operating hazards, including product liability claims and personal injury claims related to our products, to the extent deemed prudent by our management and to the extent insurance is available; however, no assurance can be given that the nature and amount of that insurance will be sufficient to fully indemnify us against liabilities arising out of pending and future claims and litigation. This insurance has deductibles or self-insured retentions and contains certain coverage exclusions. The insurance does not cover damages from breach of contract by us or based on alleged fraud or deceptive trade practices. In addition, the following risks apply with respect to our insurance coverage:

- we may not be able to continue to obtain insurance on commercially reasonable terms;
- we may be faced with types of liabilities that will not be covered by our insurance;
- our insurance carriers may not be able to meet their obligations under the policies; or
- the dollar amount of any liabilities may exceed our policy limits.

Whenever possible, we obtain agreements from customers that limit our liability. However, state law, laws or public policy in countries outside the U.S., or the negotiated terms of the agreement with the customer may not recognize those limitations of liability and/or limit the customer's indemnity obligations to the Company. In addition, insurance and customer agreements do not provide complete protection against losses and risks from an event like a well control failure that can lead to property damage, personal injury, death or the discharge of hazardous materials into the environment. Our results of operations could be adversely affected by unexpected claims not covered by insurance.

Control of oil and natural gas reserves by state-owned oil companies may impact the demand for our services and create additional risks in our operations.

Much of the world's oil and natural gas reserves are controlled by state-owned oil companies. State-owned oil companies may require their contractors to meet local content requirements or other local standards, such as joint ventures, that could be difficult or undesirable for the Company to meet. The failure to meet the local content requirements and other local standards may adversely impact the Company's operations in those countries. In addition, our ability to work with state-owned oil companies is subject to our ability to negotiate and agree upon acceptable contract terms.

Providing services on an integrated or turnkey basis generally requires the Company to assume additional risks.

Many state-owned oil companies and other operators may require integrated contracts or turnkey contracts and the Company may choose to provide services outside its core business. Providing services on an integrated or turnkey basis generally subjects the Company to additional risks, such as costs associated with unexpected delays or difficulties in drilling or completion operations and risks associated with subcontracting arrangements.

Currency fluctuations or devaluations may impact our operating results.

Fluctuations or devaluations in foreign currencies relative to the U.S. Dollar can impact our revenue and our costs of doing business. Most of our products and services are sold through contracts denominated in U.S. Dollars or local currency indexed to U.S. Dollars; however, some of our revenue, local expenses and manufacturing costs are incurred in local currencies and therefore changes in the exchange rates between the U.S. Dollar and foreign currencies can increase or decrease our revenue and expenses reported in U.S. Dollars and may impact our results of operations.

Changes in economic and/or market conditions may impact any stock repurchases, our ability to borrow and/or cost of borrowing.

To the extent the Company engages in stock repurchases, such activity is subject to economic and market conditions, such as the trading prices for our stock, as well as the terms of any stock purchase plans intended to comply with Rule 10b5-1 or Rule 10b-18 of the Exchange Act. At our discretion, we may engage in or discontinue stock repurchases at any time.

The condition of the capital markets and equity markets in general can affect the price of our common stock and our ability to obtain financing, if necessary. If the Company's credit rating is downgraded, this would increase borrowing costs under our credit facility and commercial paper program, as well as the cost of renewing or obtaining, or make it more difficult to renew or obtain or issue new debt financing.

The Company has a significant concentration of its business in North America.

During the year ended December 31, 2013, approximately one-half of our revenue and operating income were attributable to North America. In North America, a decrease in demand for energy or in oil and natural gas exploration and production, or an increase in competition could result in a significant adverse effect on our operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We own or lease numerous properties throughout the world. We consider our manufacturing plants, equipment assembly, maintenance, and overhaul facilities, grinding plants, drilling fluids and chemical processing centers, and research and technology centers to be our principal properties. The following sets forth the location of our principal owned or leased facilities for our oilfield operations by geographic segment:

North America:	Houston, Pasadena, Tomball, and The Woodlands, Texas; Broken Arrow, Claremore, Tulsa and Sand Springs, Oklahoma; Bossier City, Broussard, and Lafayette, Louisiana - all located in the United States; Leduc, Canada
Latin America:	Maracaibo, Venezuela; Macaé (Rio de Janeiro), Brazil
Europe/Africa/Russia Caspian:	Aberdeen, Scotland; Liverpool, England; Celle, Germany; Tananger, Norway; Port Harcourt, Nigeria; Tyumen, Russia
Middle East/Asia Pacific:	Dubai, United Arab Emirates; Dhahran, Saudi Arabia; Singapore, Singapore; Chonburi, Thailand

Principal properties for the Industrial Services segment include locations in Houston, Texas and Barnsdall, Oklahoma. Industrial Services also co-locates with our oilfield operations in Sand Springs, Oklahoma; Pasadena, Texas; and Liverpool, England.

We own or lease numerous other facilities such as service centers, workshops and sales and administrative offices throughout the geographic regions in which we operate. We also have a significant investment in service vehicles, tools and manufacturing and other equipment. All of our owned properties are unencumbered. We believe that our facilities are well maintained and suitable for their intended purposes.

ITEM 3. LEGAL PROCEEDINGS

We are subject to a number of lawsuits and claims arising out of the conduct of our business. The ability to predict the ultimate outcome of such matters involves judgments, estimates and inherent uncertainties. We record a liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated, including accruals for self-insured losses which are calculated based on historical claim data, specific loss development factors and other information. A range of total possible losses for all litigation matters cannot be reasonably estimated. Based on a consideration of all relevant facts and circumstances, we do not expect the ultimate outcome of any currently pending lawsuits or claims against us will have a material adverse effect on our financial position, results of operations or cash flows; however, there can be no assurance as to the ultimate outcome of these matters.

We insure against risks arising from our business to the extent deemed prudent by our management and to the extent insurance is available, but no assurance can be given that the nature and amount of that insurance will be sufficient to fully indemnify us against liabilities arising out of pending or future legal proceedings or other claims. Most of our insurance policies contain deductibles or self-insured retentions in amounts we deem prudent and for which we are responsible for payment. In determining the amount of self-insurance, it is our policy to self-insure those losses that are predictable, measurable and recurring in nature, such as claims for automobile liability, general liability and workers compensation.

On October 21, 2013, a collective action lawsuit alleging that we failed to pay an as-yet-undetermined class of workers overtime in compliance with the Fair Labor Standards Act was filed titled *Zamora et al. v. Baker Hughes Incorporated, Civil Action No. 2:13-CV-00326*, in the U.S. District Court for the Southern District of Texas, Corpus Christi Division. On October 10, 2013, a class and collective action lawsuit alleging that we failed to pay a nationwide class of workers overtime in compliance with the Fair Labor Standards Act and certain state laws was filed titled *Lea et al. v. Baker Hughes, Inc., Civil Action No. 3:13-CV-00447*, in the U.S. District Court for the Southern District of Texas, Galveston Division. We are evaluating the background facts and at this time cannot provide an evaluation of the likelihood of an unfavorable outcome or potential settlement terms.

On May 30, 2013, we received a Civil Investigative Demand ("CID") from the United States Department of Justice ("DOJ") pursuant to the Antitrust Civil Process Act. The CID seeks documents and information from us for the period from May 29, 2011 through the date of the CID in connection with a DOJ investigation related to pressure pumping services in the United States. We are working with the DOJ to provide the requested documents and information. We are not able to predict what action, if any, might be taken in the future by the DOJ or other governmental authorities as a result of the investigation.

On September 19, 2012, our subsidiary, Baker Hughes Oilfield Operations, Inc. (“BHOO”) terminated a sand supply agreement it had entered into with Hi-Crush Operating, LLC (“Hi-Crush”) on October 28, 2011 (as amended by the First Amendment to Supply Agreement on May 10, 2012, collectively the “Supply Agreement”) as a result of Hi-Crush's breach of the Supply Agreement. On November 12, 2012, Hi-Crush filed a lawsuit against BHOO in the 129th Judicial District Court in Harris County, Texas., *Cause No. 2012-67261; Hi-Crush Operating, LLC v. Baker Hughes Oilfield Operations, Inc.* In its petition, Hi-Crush claimed that BHOO's termination was “invalid” constituting a breach and that BHOO “anticipatorily repudiated the Supply Agreement without just excuse.” Hi-Crush claimed that it was entitled to recover liquidated damages of $187 million based on the undelivered Minimum Purchase Requirement provision defined in the Supply Agreement; in the alternative, Hi-Crush sought an unspecified amount of actual damages. On December 17, 2012, BHOO filed a responsive pleading denying Hi-Crush's allegations and also filed a counter claim for breach of contract. On October 10, 2013, BHOO and Hi-Crush entered into a settlement agreement pursuant to which both parties agreed to jointly dismiss the above litigation. In connection with this settlement agreement, the parties have entered into a new supply agreement. The settlement agreement did not have a material impact on our financial position, results of operations or cash flows.

We were among several unrelated companies who received a subpoena from the Office of the New York Attorney General, dated June 17, 2011. The subpoena received by the Company seeks information and documents relating to, among other things, natural gas development and hydraulic fracturing. We are discussing the subpoena with the New York Attorney General's office.

ITEM 4. MINE SAFETY DISCLOSURES

Our barite mining operations, in support of our drilling fluids products and 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 is included in Exhibit 95 to this report.

PART II

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

Our common stock, $1.00 par value per share, is principally traded on the New York Stock Exchange. Our common stock is also traded on the SIX Swiss Exchange. As of February 7, 2014, there were approximately 10,300 stockholders of record.

For information regarding quarterly high and low sales prices on the New York Stock Exchange for our common stock during the two years ended December 31, 2013, and information regarding dividends declared on our common stock during the two years ended December 31, 2013, see Note 13 of the Notes to Consolidated Financial Statements in Item 8 herein.

The following table contains information about our purchases of equity securities during the fourth quarter of 2013.

Issuer Purchases of Equity Securities

Period	Number of Shares Purchased (1)	Average Price Paid Per Share (1)	Number of Shares Purchased as Part of a Publicly Announced Program (2)	Average Price Paid Per Share (3)	Total Number of Shares Purchased in the Aggregate	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Program (4)
October 1-31, 2013	2,860	$ 55.67	—	$ —	2,860	$ —
November 1-30, 2013	101	56.73	2,877,310	57.34	2,877,411	—
December 1-31, 2013	—	—	3,422,161	54.12	3,422,161	—
Total	2,961	$ 55.70	6,299,471	$ 55.59	6,302,432	$ 1,649,956,974

(1) Represents shares purchased from employees to satisfy the tax withholding obligations in connection with the vesting of restricted stock awards and restricted stock units.

(2) Repurchases were made under our previously announced purchase program, including under a Letter Agreement with an agent that complied with the requirements of Rule 10b-18 of the Exchange Act (the "Agreement"). Shares were repurchased under the Agreement by the agent at the prevailing market prices, in open market transactions. Additionally, on December 10, 2013, we entered into a Purchase Plan that complied with Rule 10b5-1 of the Exchange Act (the "10b5-1 Plan"). Under the 10b5-1 Plan, the agent repurchased a number of shares of our common stock determined under the terms of the 10b5-1 Plan each trading day based on the trading price of the stock on that day.

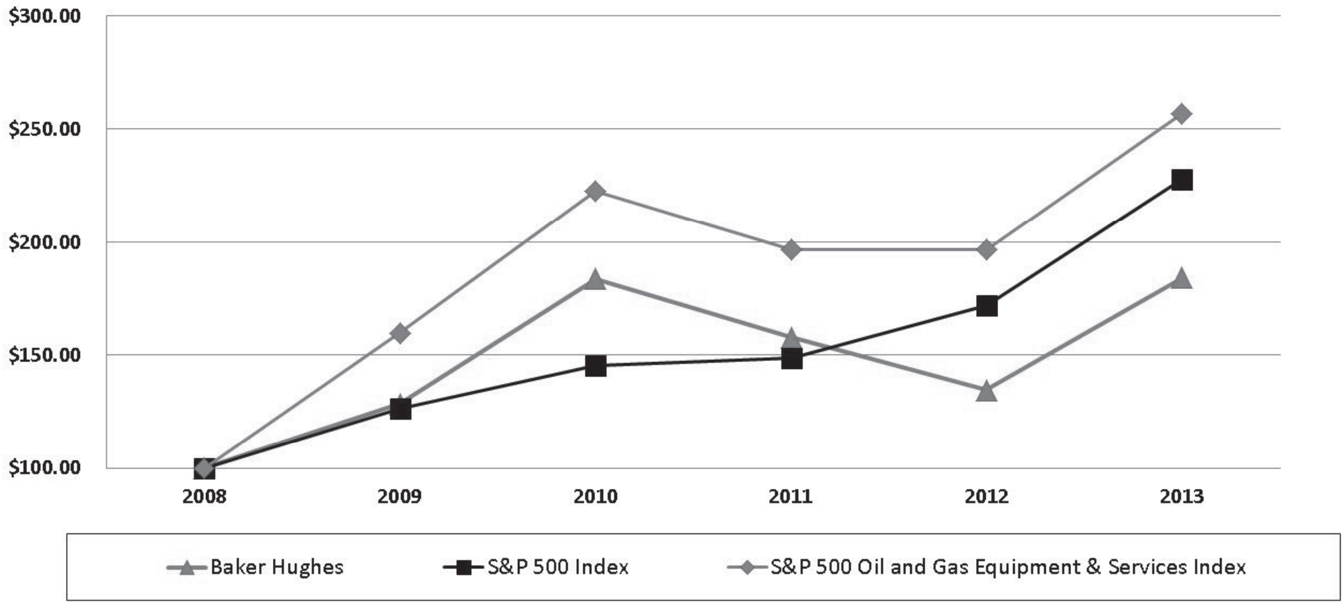
(3) Average price paid includes commissions.

(4) During 2013, our Board of Directors increased the authorization to purchase our common stock under our previously announced program by $800 million. During the fourth quarter of 2013, we repurchased 6.3 million shares of our common stock at an average price of $55.59 per share (including commissions), for a total of $350 million. We had authorization remaining to repurchase up to a total of $1.65 billion of our common stock as of the end of 2013.

Corporate Performance Graph

The following graph compares the yearly change in our cumulative total stockholder return on our common stock (assuming reinvestment of dividends into common stock at the date of payment) with the cumulative total return on the published Standard & Poor's ("S&P") 500 Stock Index and the cumulative total return on the S&P 500 Oil and Gas Equipment and Services Index over the preceding five-year period.

Comparison of Five-Year Cumulative Total Return *
Baker Hughes Incorporated; S&P 500 Index and S&P 500 Oil and Gas Equipment and Services Index



	2008	2009	2010	2011	2012	2013
Baker Hughes	$100.00	$128.33	$183.60	$157.85	$134.45	$184.13
S&P 500 Index	100.00	126.37	145.36	148.45	172.10	227.72
S&P 500 Oil and Gas Equipment and Services Index	100.00	159.80	222.47	196.63	196.69	256.96

* Total return assumes reinvestment of dividends on a quarterly basis.

The comparison of total return on investment (change in year-end stock price plus reinvested dividends) assumes that $100 was invested on December 31, 2008 in Baker Hughes common stock, the S&P 500 Index and the S&P 500 Oil and Gas Equipment and Services Index.

The corporate performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that Baker Hughes specifically incorporates it by reference into such filing.

ITEM 6. SELECTED FINANCIAL DATA

The Selected Financial Data should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data, both contained herein.

	Year Ended December 31,				
(In millions, except per share amounts)	**2013** [(1)]	**2012** [(1)]	**2011** [(1)]	**2010** [(1)]	**2009**
Revenue	$ 22,364	$ 21,361	$ 19,831	$ 14,414	$ 9,664
Operating income [(2)]	1,949	2,192	2,600	1,417	732
Non-operating expense, net	(234)	(210)	(261)	(135)	(121)
Income before income taxes	1,715	1,982	2,339	1,282	611
Income taxes [(3)]	(612)	(665)	(596)	(463)	(190)
Net income	1,103	1,317	1,743	819	421
Net (income) loss attributable to noncontrolling interests	(7)	(6)	(4)	(7)	—
Net income attributable to Baker Hughes	$ 1,096	$ 1,311	$ 1,739	$ 812	$ 421
Per share of common stock:					
Net income attributable to Baker Hughes:					
Basic	$ 2.47	$ 2.98	$ 3.99	$ 2.06	$ 1.36
Diluted	2.47	2.97	3.97	2.06	1.36
Dividends	0.60	0.60	0.60	0.60	0.60
Balance Sheet Data:					
Cash, cash equivalents and short-term investments	$ 1,399	$ 1,015	$ 1,050	$ 1,706	$ 1,595
Working capital (current assets minus current liabilities)	6,717	6,293	6,295	5,568	4,612
Total assets	27,934	26,689	24,847	22,986	11,439
Long-term debt	3,882	3,837	3,845	3,554	1,785
Total equity	17,912	17,268	15,964	14,286	7,284

Notes To Selected Financial Data

(1) We acquired BJ Services Company ("BJ Services") on April 28, 2010, and accordingly, the financial results of BJ Services are included only from the date of acquisition.

(2) Operating income for 2011 includes a charge of $315 million before-tax ($220 million net of tax), the majority of which relates to the impairment associated with the decision to minimize the use of the BJ Services trade name. For further discussion, see Note 7 of the Notes to Consolidated Financial Statements in Item 8 herein.

(3) Income taxes for 2011 include a tax benefit of $214 million associated with the reorganization of certain foreign subsidiaries. For further discussion, see Note 3 of the Notes to Consolidated Financial Statements in Item 8 herein.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data contained herein.

EXECUTIVE SUMMARY

Baker Hughes is a leading supplier of oilfield services, products, technology and systems to the worldwide oil and natural gas industry, referred to as our oilfield operations. We manage our oilfield operations through four geographic segments consisting of North America, Latin America, Europe/Africa/Russia Caspian, and Middle East/Asia Pacific. Our Industrial Services businesses are reported in a fifth segment.

The main products and services provided by oilfield operations fall into one of two categories, Drilling and Evaluation or Completion and Production. This classification is based on the two major phases of constructing an oil and/or natural gas well, the drilling phase and the completion phase, and how our products and services are utilized in each phase. We also provide products and services to the downstream chemicals, and process and pipeline industries, referred to as Industrial Services.

Within our oilfield operations, the primary driver of our businesses is our customers' capital and operating expenditures dedicated to oil and natural gas exploration, field development and production. Our business is cyclical and is dependent upon our customers' expectations for future oil and natural gas prices, economic growth, hydrocarbon demand and estimates of current and future oil and natural gas production.

For 2013, we generated revenue of $22.36 billion, an increase of $1 billion, or 5%, compared to 2012. Revenue from our North America segment for 2013 was $10.88 billion, which was flat compared to 2012. Revenue for our Latin America segment for 2013 was $2.31 billion, a decrease of 4% compared to 2012. The Western Hemisphere was negatively impacted by activity declines in several markets, particularly in the U.S., Canada and Brazil where rig counts were below 2012 levels. Revenue from the Eastern Hemisphere was $7.90 billion, an increase of 14% compared to 2012. Revenue in our Middle East/Asia Pacific segment grew $775 million, or 24%, in 2013 compared to 2012. Industrial Services revenue was $1.28 billion, an increase of 5% compared to 2012.

Net income attributable to Baker Hughes was $1.10 billion for 2013 compared to $1.31 billion for 2012. Profit before tax for our North America segment was $968 million in 2013 compared to $1.27 billion in 2012. Profitability in North America was adversely impacted by the continued over supply of pressure pumping capacity in the market. This was partially mitigated by increased activity and margins in the Gulf of Mexico. Profit before tax for our Latin America segment was $66 million in 2013 compared to $197 million in 2012. Profitability in Latin America declined due to reduced activity and lower pricing in Brazil and severance costs incurred across the entire segment as we realigned our business to respond to lower activity levels. Profit before tax for the Eastern Hemisphere was $1.05 billion in 2013 compared to $899 million in 2012. The increase in profitability in the Eastern Hemisphere was driven primarily by the activity increases and improved profitability in Asia Pacific and Russia Caspian.

As of December 31, 2013, Baker Hughes had approximately 59,400 employees compared to approximately 58,800 employees as of December 31, 2012.

BUSINESS ENVIRONMENT

In North America, customer spending decreased in 2013 compared to 2012, resulting in a 7% decrease in the North America rig count. Natural gas-directed drilling activity decreased 23% in 2013 compared to 2012 as increased production in unconventional natural gas shale basins contributed to high natural gas working inventories and ultimately low commodity prices. In the U.S., low natural gas prices resulted in reduced customer spending in the natural gas shale basins, resulting in a 31% reduction in natural gas-directed rig activity in 2013 compared to 2012. Oil-directed rig activity in the U.S. increased by 1% during the same period. In Canada, high oil price differentials primarily due to constrained refinery and pipeline capacity resulted in an 11% reduction in oil-directed customer activity. This was offset by an 18% increase in natural gas-directed rigs driven by drilling in condensate rich zones in Alberta to service activity in the oil sands. These issues ultimately resulted in a 3% reduction in Canadian rig activity in 2013 compared to 2012.

Outside of North America, customer spending is most heavily influenced by Brent oil prices. Due to the long-term planning cycles associated with many international projects, customers do not tend to react to short-term movements in oil prices. On average, Brent oil prices were flat in 2013 compared to 2012. During 2013, upward pricing pressure, resulting from geopolitical tensions in the Middle East, was offset by weak European demand caused by Europe's economic downturn, uncertainty regarding future economic growth in China and increasing global oil supplies. Despite overall flat oil prices, our customers' activity and spending levels increased moderately in 2013 compared to 2012. As a result, the international rig count grew by 5% in 2013 compared to 2012, with the largest gains seen in Africa, the Middle East and Continental Europe.

Oil and Natural Gas Prices

Oil and natural gas prices are summarized in the table below as averages of the daily closing prices during each of the periods indicated.

	2013	2012	2011
Brent oil prices ($/Bbl) (1)	$ 108.81	$ 111.96	$ 111.05
WTI oil prices ($/Bbl) (2)	97.98	94.12	95.08
Natural gas prices ($/mmBtu) (3)	3.73	2.76	3.99

(1) Bloomberg Dated Brent ("Brent") Oil Spot Price per Barrel
(2) Bloomberg West Texas Intermediate ("WTI") Cushing Crude Oil Spot Price per Barrel
(3) Bloomberg Henry Hub Natural Gas Spot Price per million British Thermal Unit

Brent oil prices averaged $108.81/Bbl in 2013. Brent oil prices fluctuated throughout the year, with the highest prices being seen in the first quarter as geopolitical disputes in the Middle East and Africa reduced output and threatened future production. Overall, prices ranged from a high of $119.34/Bbl in February 2013 to a low of $96.79/Bbl in April 2013. The low price in April was the result of unfavorable economic data from the U.S., Europe and China that led to negative demand forecasts and fears of a global economic downturn. These fears eased during the early summer months, and prices stabilized for the remainder of the year near the 2013 average price of $108.81/Bbl. The International Energy Agency ("IEA") estimated in its January 2014 Oil Market Report that worldwide demand increased 1.2 million barrels per day to 91.2 million barrels per day in 2013 when compared to 2012.

WTI oil prices averaged $97.98/Bbl in 2013. Similar to Brent oil prices, WTI oil prices fluctuated throughout the year, with the highest prices being recorded in the third quarter. Overall, WTI oil prices ranged from a low of $86.68/Bbl in April 2013 to a high of $110.53/Bbl in September 2013. High prices during the third quarter were a result of WTI crude increasingly displacing Brent-quality crude imports into North America through increased U.S. oil production and improved crude-by-rail and pipeline infrastructure. The Brent-WTI spread, or the difference between the spot prices of Brent and WTI crude oils, narrowed to within $0.66/Bbl during the third quarter, which represented the lowest spread in three years. The spread widened significantly during the fourth quarter, however, as WTI prices were pressured downward by increased supplies of light grade oil in the U.S., while Brent prices were supported upward by temporary reductions in Libyan production due to increased political tensions. The Brent-WTI spread closed the year in 2013 with a differential of $12.40/Bbl.

In North America, natural gas prices, as measured by the Henry Hub Natural Gas Spot Price, averaged $3.73/mmBtu in 2013. Natural gas prices increased 35% during 2013 from 2012 average levels. Natural gas prices improved throughout the year due to lower storage levels and reduced natural gas-directed rig counts. Overall, natural gas prices ranged from a low of $3.08/mmBtu in January 2013 to a high of $4.52/mmBtu in December 2013. According to the U.S. Department of Energy ("DOE"), working natural gas in storage at the end of 2013 was 2,974 billion cubic feet ("Bcf"), which was 16% or 562 Bcf below the corresponding week in 2012.

Baker Hughes Rig Count

Baker Hughes has been providing rig counts to the public since 1944. We gather all relevant data through our field service personnel, who obtain the necessary data from routine visits to the various rigs, customers, contractors and/or other outside sources. We base the classification of a well as either oil or natural gas primarily upon filings made by operators in the relevant jurisdiction. This data is then compiled and distributed to various wire services and trade associations and is published on our website. We believe the counting process and resulting data is reliable; however, it is subject to our ability to obtain accurate and timely information. Rig counts are compiled weekly for the U.S. and Canada and monthly for all international rigs. Published international rig counts do not include rigs drilling in certain locations, such as Russia, the Caspian, Iran and onshore China because this information is not readily available. Baker Hughes resumed publication in June 2012 of the rig count in Iraq for the first time since August 1990.

Rigs in the U.S. and Canada are counted as active if, on the day the count is taken, the well being drilled has been started but drilling has not been completed and the well is anticipated to be of sufficient depth to be a potential consumer of our drill bits. In international areas, rigs are counted on a weekly basis and deemed active if drilling activities occurred during the majority of the week. The weekly results are then averaged for the month and published accordingly. The rig count does not include rigs that are in transit from one location to another, rigging up, being used in non-drilling activities, including production testing, completion and workover, and are not expected to be significant consumers of drill bits.

The Baker Hughes Rig Counts are an important business barometer for the drilling industry and its suppliers. When drilling rigs are active they consume products and services produced by the oil service industry. Rig count trends are governed by the exploration and development spending by oil and gas companies, which in turn is influenced by current and future price expectations for oil and gas. Therefore, the counts may reflect the relative strength and stability of energy prices and overall market activity. However, these counts should not be solely relied on as other specific and pervasive conditions may exist that affects overall energy prices and market activity.

The rig counts are summarized in the table below as averages for each of the periods indicated.

	2013	2012	2011
U.S. - onshore	1,705	1,871	1,846
U.S. - offshore	56	47	32
Canada	353	364	418
North America	2,114	2,282	2,296
Latin America	419	423	424
North Sea	42	40	38
Continental Europe	93	79	80
Africa	125	96	78
Middle East	372	356	291
Asia Pacific	246	241	256
Outside North America	1,297	1,235	1,167
Worldwide	3,411	3,517	3,463

2013 Compared to 2012

The rig count in North America decreased 7% in 2013 compared to 2012 primarily driven by a 23% decline in natural gas-directed rigs. The oil-directed rig count declined 1%. The natural gas-directed rig count reflected a 31% decrease in the U.S. offset by an 18% increase in Canada. The oil-directed rig count increased 1% in the U.S., but decreased by 11% in Canada. Natural gas-directed drilling in the U.S. was negatively impacted by the continued weakness in North America natural gas prices which discouraged new investment in natural gas fields. In Canada, the increase in natural gas-directed rigs was driven by drilling in condensate rich zones in Alberta to service the oil sands drilling activity. In Canada, many operators curtailed their oil-directed drilling plans in the second half of 2013 due to high oil price differentials as compared to WTI and wet weather in southern Alberta and Saskatchewan. Overall, Canada rig counts decreased 3% in 2013 compared to 2012.

Outside North America, the rig count increased 5% in 2013 compared to 2012. The rig count in Latin America was relatively flat as increased rig activity in Argentina and Ecuador was offset by reductions in Brazil and Colombia. The rig count in Continental Europe increased by 18% with higher activity in Turkey, the Balkans, and Sakhalin. The North Sea rig count increased by 5%, primarily due to increased activity in Norway. In Africa, the rig count increased primarily due to the resumption of drilling activities in Libya, as well as higher activity in Algeria and Kenya. The rig count increased 5% in the Middle East due to higher activity in Iraq, Abu Dhabi and Pakistan offset by a reduction in Egypt due to political unrest.

2012 Compared to 2011

The rig count in North America decreased 1% in 2012 compared to 2011 as natural gas-directed rig counts declined 36%, largely offset by an increase in oil-directed rig counts of 28%. The natural gas-directed rig count reflected a 37% decrease in the U.S. and a 27% decrease in Canada. The oil-directed rig count increased 38% in the U.S., but was slightly offset by a 6% decrease in Canada. Natural gas-directed drilling was negatively impacted by the continued weakness in North America natural gas prices which discouraged new investment in natural gas fields. The growth in oil-directed drilling in the U.S. was primarily a result of strong oil prices and the industry's ability to apply drilling and completion techniques to unconventional oil reservoirs that were originally applied to similar natural gas reservoirs. In Canada, many operators curtailed their drilling plans in the second half of 2012 due to reduced cash flows from natural gas activities and high oil price differentials as compared to WTI. Overall, Canada rig counts declined 13% in 2012 compared to 2011.

Outside North America, the rig count increased 6% in 2012 compared to 2011. Starting June 2012, the Middle East rig count included Iraq. Excluding Iraq, which had an average of 43 rigs in 2012, the international rig count increased 2%. The rig count in Latin America was relatively flat as increased rig activity in Mexico and Ecuador was offset by reductions in Colombia and Venezuela. The rig count in Europe was also flat, with gains in the North Sea due to higher activity in the U.K. offset by reductions in Continental Europe. In Africa, the rig count increased primarily due to the resumption of drilling activities in Libya, as well as higher activity in Algeria. The rig count increased in the Middle East due to higher activity in Saudi Arabia, Oman and Abu Dhabi, as well as the inclusion of Iraq. In Asia Pacific, the rig count decreased as a result of decreased activity in Indonesia and offshore China, partially offset by increased activity in Malaysia and Australia.

Baker Hughes Well Count

Baker Hughes began providing U.S. well count data to the oil and natural gas industry in July 2013. The Baker Hughes Well Count is an extension of the Baker Hughes Rig Count, and provides a quarterly census of the number of new onshore oil and natural gas wells where drilling began, or spud, in the U.S. The Baker Hughes Well Count includes wells that are identified to be significant consumers of oilfield services and supplies, and excludes wells categorized as workover, plugged and abandoned or completed. Well count trends are governed by oil company exploration and development spending in the U.S., which in turn is influenced by the current and expected price of oil and natural gas. Well counts therefore may reflect the strength and stability of energy prices. However, there are many other factors that can influence the well count, including new technologies, pad drilling, weather, seasonal spending and changes to local regulations. We believe the counting process and resulting data is reliable; however, it is subject to our ability to obtain accurate and timely information.

During 2013, 35,676 wells were spud on land in the U.S. This compares to 36,824 wells spud in 2012, or a reduction of 3%.

RESULTS OF OPERATIONS

The discussions below relating to significant line items from our consolidated statements of income are based on available information and represent our analysis of significant changes or events that impact the comparability of reported amounts. Where appropriate, we have identified specific events and changes that affect comparability or trends and, where reasonably practicable, have quantified the impact of such items. In addition, the discussions below for revenue and cost of revenue are on a total basis as the business drivers for product sales and services are similar. All dollar amounts in tabulations in this section are in millions of dollars, unless otherwise stated.

Revenue and Profit Before Tax

Revenue and profit before tax for each of our five operating segments is provided below. The performance of our segments is evaluated based on profit before tax, which is defined as income before income taxes and before the following: net interest expense, corporate expenses, and certain gains and losses not allocated to the segments.

2013 Compared to 2012

	Year Ended December 31, 2013	Year Ended December 31, 2012	$ Change	% Change
Revenue:				
North America	$ 10,878	$ 10,836	$ 42	— %
Latin America	2,307	2,399	(92)	(4)%
Europe/Africa/Russia Caspian	3,850	3,634	216	6 %
Middle East/Asia Pacific	4,050	3,275	775	24 %
Industrial Services	1,279	1,217	62	5 %
Total Revenue	$ 22,364	$ 21,361	$ 1,003	5 %

	Year Ended December 31, 2013	Year Ended December 31, 2012	$ Change	% Change
Profit Before Tax:				
North America	$ 968	$ 1,268	$ (300)	(24)%
Latin America	66	197	(131)	(66)%
Europe/Africa/Russia Caspian	570	586	(16)	(3)%
Middle East/Asia Pacific	478	313	165	53 %
Industrial Services	135	131	4	3 %
Total Operations	2,217	2,495	(278)	(11)%
Corporate and other	(502)	(513)	11	(2)%
Total Profit Before Tax	$ 1,715	$ 1,982	$ (267)	(13)%

Revenue for 2013 increased $1 billion, or 5%, compared to 2012, with the increase coming predominantly from the Eastern Hemisphere as we continue to grow our operations in the Middle East, Asia Pacific, Africa and Russia Caspian. In North America, revenue growth in the Gulf of Mexico was essentially offset by lower revenue in Canada.

Profit before tax from operations for 2013 decreased $278 million, or 11%, compared to 2012. Despite the increase in revenue, our profit before tax was significantly impacted by low equipment utilization resulting from over capacity in the pressure pumping business in North America, a decline in activity and lower prices for drilling services in Brazil, and reduced pricing and increased start-up costs associated with the new drilling contract in Norway. During the fourth quarter of 2013, we incurred costs of $79 million in Iraq related to a significant disruption to operations, increased personnel and security costs, and other non-recurring items. By the end of December 2013, with the additional security measures in place, our operations in Iraq had resumed. These reductions to profit before tax were partially offset by Asia Pacific, which experienced a significant improvement in profitability throughout the region driven by increased activity and improved mix of product sales.

In 2013, we incurred a charge of $23 million before-tax related to the currency devaluation in Venezuela as well as severance charges of $56 million before-tax due to restructuring of our business to match current market conditions throughout all regions. In 2012, profit before tax included charges of $63 million, of which $43 million related to the impairment of certain information technology assets primarily associated with internally developed software and other assets, and $20 million related to the closure of a chemical manufacturing facility in the U.K. As our information technology and supply chain organizations support our global operations, these charges were allocated to all segments. The amount of the impairment charges recorded by segment in 2012 was as follows: North America - $33 million; Latin America - $7 million; Europe/Africa/Russia Caspian - $11 million; Middle East/Asia Pacific - $10 million; and Industrial Services - $2 million.

North America

North America revenue was flat in 2013 compared to 2012, despite rig counts declining 7%. Revenue in the Gulf of Mexico increased in-line with the rig count increase of 17% compared to 2012. The main drivers for the revenue growth in the Gulf of Mexico were increased activity in our drilling and completion fluids, pressure pumping, completion systems and wireline services product lines. Despite a 9% decline in the U.S. onshore rig count in 2013 compared to 2012, driven by lower natural gas-directed rigs, total revenue for our U.S. onshore business was flat year over year. During 2013, we experienced revenue growth in our U.S. onshore drilling services, artificial lift and completion systems product lines. However, these increases were mostly offset by reduced revenue in our drilling and completion fluids and pressure pumping product lines. Although we experienced share gains in 2013 compared to 2012 in our pressure pumping product line across several basins in the U.S., revenue declined in our pressure pumping business due to the continued oversupply of pressure pumping capacity in the industry. Revenue in Canada declined in 2013 as compared to 2012, in part due to an 11% decline in the oil-directed rig count, which is a significant driver of our operations in the country. Our revenue in Canada was also negatively impacted by a decline in our pressure pumping product line, where we experienced lower demand for hydraulic fracturing. An unfavorable change in the Canadian exchange rate relative to the U.S. Dollar also contributed to the year over year revenue decline.

North America profit before tax was $968 million in 2013, a decrease of $300 million, or 24%, compared to 2012. Profits from our U.S. onshore and Canadian operations were significantly impacted by the continued oversupply of pressure pumping equipment, resulting in low fleet utilization and increased competition. North America profit before tax was further reduced by higher depreciation and amortization expense of $64 million and higher compensation costs. These reductions were partially offset by improved profits in the Gulf of Mexico resulting from a favorable mix of sales to deepwater completion systems and pressure pumping services, as well as lower costs for raw materials, and other efficiency gains and cost savings recognized as part of our pressure pumping profit improvement plan. In 2012, North America profit before tax was negatively impacted by the impairment charges associated with the information technology assets and facility closure discussed previously.

Latin America

Latin America revenue decreased 4% in 2013 compared to 2012. The primary drivers were reduced revenues in Brazil and Venezuela, partially offset by increased revenues throughout the rest of the region. Activity declined across almost all product lines in Brazil in part due to a 23% reduction in the rig count as compared to 2012, but also due to a new drilling services contract with lower activity and pricing. Revenue in Venezuela decreased across almost all product lines due to lower activity levels and the impact of a devaluation in the local currency. These decreases were partially offset by increased revenues for our drilling services and artificial lift product lines in Ecuador, pressure pumping and wireline services in Argentina, and pressure pumping and drilling services in Mexico.

Latin America profit before tax decreased $131 million, or 66%, in 2013 compared to 2012. The main drivers behind this reduction were lower revenues and pricing for our drilling services product line in Brazil, expenses associated with demobilization of equipment in Brazil, lower activity levels in Venezuela, and severance charges of $32 million throughout Latin America. In February 2013, Venezuela's currency was devalued from the prior exchange rate of 4.3 Bolivars Fuertes per U.S. Dollar to 6.3 Bolivars Fuertes per U.S. Dollar, which applies to our local currency denominated balances. The impact of this devaluation was a loss of $23 million that was recorded in marketing, general and administrative expense in the first quarter of 2013. In 2012, Latin America profit before tax was negatively impacted by the impairment charges associated with the information technology assets and facility closure discussed previously.

In January 2014, Venezuela announced the establishment of a dual exchange rate system whereby a rate of 6.3 Bolivares Fuertes to the U.S. Dollar will be applied to certain economic sectors, such as food and medicine, while other sectors of the economy will apply an exchange rate determined based on the results of the Venezuelan central bank's system of weekly currency auctions. While the functional currency of our operations in Venezuela is the U.S. Dollar, a portion of the transactions and balances are denominated in Bolivares Fuertes. For financial reporting purposes, such local currency transactions are remeasured into U.S. Dollars at the official exchange rate of 6.3 Bolivares Fuertes to the U.S. Dollar. We are assessing the applicability and impact, if any, of the potential change in exchange rates. If we were required to apply a different exchange rate, we may incur a loss in 2014. For example, if we were to apply an exchange rate of 11.3 Bolivares Fuertes per U.S. Dollar (the rate per the most recent auction) to our local currency denominated balances at December 31, 2013, it would result in a loss of approximately $10 million.

Europe/Africa/Russia Caspian ("EARC"*)*

EARC revenue increased 6% in 2013 compared to 2012. Revenue increased in both Africa and Russia Caspian, with Europe remaining flat. The increase in Africa was predominantly in Nigeria, where our drilling services and completion systems product lines experienced increased activity, as well as in North Africa, where the resumption of activity in Libya benefited our drilling services, wireline services and completion systems product lines. Increased activity in Algeria and share gains in Mauritania also contributed to increased revenues compared to 2012. Growth in Russia Caspian was due to increased demand for our drilling services, completion systems, pressure pumping and artificial lift product lines. In Europe, revenue was flat compared to 2012. A new drilling services contract and higher activity for pressure pumping and wireline services in Norway were offset by the completion of significant projects in the Eastern Mediterranean and lower activity across all drilling and evaluation product lines in the United Kingdom.

EARC profit before tax decreased $16 million, or 3%, in 2013 compared to 2012. In Europe, profit margins declined due to reduced pricing and increased start-up costs associated with the new drilling services contract in Norway. Europe profitability was also impacted by the reduced drilling and evaluation activity in the United Kingdom and completion of the projects in the Eastern Mediterranean. These declines were partially mitigated by improved profits in Africa and Russia Caspian, primarily associated with higher revenue. In 2012, EARC profit before tax was negatively impacted by the impairment charges associated with the information technology assets and facility closure discussed previously.

Middle East/Asia Pacific ("MEAP"*)*

MEAP revenue increased 24% in 2013 compared to 2012, while the corresponding rig count increased only 4% over the same period. Both the Middle East and Asia Pacific posted strong revenue growth in all geographies, most notably in Iraq, Saudi Arabia, the Arabian Gulf, Southeast Asia and China. Iraq revenue increased due to growth in our integrated services contracts. However, Iraq revenue was negatively impacted in the fourth quarter of 2013 due to a significant disruption in operations. Saudi Arabia saw a significant increase in revenue due to higher demand for our drilling services, pressure pumping and wireline services product lines as well as growth in an integrated services contract. Revenue increased in the Arabian Gulf due to increased demand for our drilling services and wireline services product lines in United Arab Emirates, as well as for wireline services in India. Within Asia Pacific, revenue growth was strongest in South East Asia for drilling services, completion systems and pressure pumping. Indonesia and China experienced increased activity for drilling services, and demand for wireline services grew in Papua New Guinea.

MEAP profit before tax improved $165 million, or 53%, in 2013 compared to 2012. The primary driver of the increase in profit before tax was higher incremental profit on increased revenue in Asia Pacific, and to a lesser extent in the Middle East. Further, we experienced a favorable shift in product mix with a higher proportion of revenue derived from our drilling services and completion systems product lines. Profit before tax in 2013 also benefited from ongoing profit improvement initiatives in Asia Pacific. These improvements were offset by $79 million of losses in Iraq related to the significant disruption to our operations, expenses associated with personnel movements and security measures, and other nonrecurring items. In 2012, MEAP profit before tax was negatively impacted by the impairment charges associated with the information technology assets and facility closure discussed previously.

Industrial Services

For Industrial Services, revenue increased 5% and profit before tax increased 3% in 2013 compared to 2012. The increase in revenue was primarily driven by increased demand for our process and pipeline business. The increase in profit before tax is due to the revenue increase offset by higher compensation expenses. In 2012, Industrial Services profit before tax was negatively impacted by the impairment charges associated with information technology assets and facility closure discussed previously.

2012 Compared to 2011

	Year Ended December 31,			
	2012	2011	$ Change	% Change
Revenue:				
North America	$ 10,836	$ 10,279	$ 557	5%
Latin America	2,399	2,190	209	10%
Europe/Africa/Russia Caspian	3,634	3,372	262	8%
Middle East/Asia Pacific	3,275	2,852	423	15%
Industrial Services	1,217	1,138	79	7%
Total Revenue	$ 21,361	$ 19,831	$ 1,530	8%

	Year Ended December 31,			
	2012	2011	$ Change	% Change
Profit Before Tax:				
North America	$ 1,268	$ 1,908	$ (640)	(34)%
Latin America	197	223	(26)	(12)%
Europe/Africa/Russia Caspian	586	336	250	74 %
Middle East/Asia Pacific	313	310	3	1 %
Industrial Services	131	95	36	38 %
Total Operations	2,495	2,872	(377)	(13)%
Corporate and other	(513)	(533)	20	(4)%
Total Profit Before Tax	$ 1,982	$ 2,339	$ (357)	(15)%

Revenue for 2012 increased $1.53 billion or 8% compared to 2011 with growth coming from all segments. Revenue growth in North America was driven by increased demand in the U.S. for product lines other than pressure pumping and increased activity in deepwater drilling in the Gulf of Mexico. International revenue increased primarily as a result of increased activity in the Middle East, Latin America and Africa.

Profit before tax from operations for 2012 decreased $377 million or 13% compared to 2011. Despite the increase in revenue, our profit before tax was significantly impacted by reduced prices, increased raw material expenses and higher personnel costs in our pressure pumping product line in North America. Additional provisions for doubtful accounts in Latin America and high operating costs and third party expenses related to new integrated operations contracts in the Middle East impacted profits in Latin America and MEAP. EARC experienced improved profitability driven by increased activity throughout the entire segment as well as improved market conditions in Africa.

In 2012, we incurred charges of $63 million associated with the impairment of certain information technology assets and the closure of a chemical manufacturing facility in the U.K, as discussed above in our comparison of operating results from 2013 to 2012. In 2011, profit before tax included a charge of $315 million related to the impairment of trade names. For further discussion of the trade name impairments see Note 7. Goodwill and Intangible Assets. The amount of the trade name impairment charge recorded by segment was as follows: North America - $105 million; Latin America - $64 million; Europe/Africa/Russia Caspian - $48 million; Middle East/Asia Pacific - $47 million; and Industrial Services - $51 million.

North America

North America revenue increased 5% in 2012 compared to 2011 despite rig counts declining 1%. The primary catalysts for the revenue growth in North America include sustained high oil prices during 2012 compared to historical prices and new innovative technologies for drilling and completion systems and wireline services that have resulted in increased revenue, particularly in the unconventional reservoirs in the U.S. and deepwater of the Gulf of Mexico. Additionally, the continuing shift of drilling activities from the natural gas-directed unconventional reservoirs to the oil-directed reservoirs in the U.S. resulted in significant increases in activity particularly for our production product lines, artificial lift and upstream chemicals. In the Gulf of Mexico, revenue increased 32% in 2012 compared to 2011 as rig counts increased 47%, driven primarily by increased deepwater activity. These increases in revenue were offset by reduced demand and pricing in our pressure pumping product line in the U.S. and Canada primarily due to an oversupply of pressure pumping capacity in the industry. Additionally, as a result of reduced customer spending in Canada, oil-directed rig counts decreased 6% and natural gas-directed rig counts were down 27% compared to 2011. Overall, this resulted in a 10% reduction in our Canadian revenue during 2012 compared to 2011.

North America profit before tax was $1.27 billion in 2012, a decrease of $640 million, or 34%, compared to 2011. Despite higher revenue, profits in U.S. and Canada were impacted significantly by decreased fleet utilization and lower pricing, higher personnel costs, and increased costs for critical raw materials primarily in our pressure pumping product line. Additionally, higher depreciation and amortization expense of $125 million also contributed to a decrease in profitability. Profit before tax in Canada was further impacted by the reduced customer spending. These reductions were partially offset by increased activity in our U.S. product lines other than pressure pumping and improved profits in the Gulf of Mexico, where both revenue and profit margins returned to pre-moratorium levels as activity increased substantially. During 2012, deepwater drilling activity increased significantly compared to shelf drilling activity. The shift from shelf activity to deepwater activity led to a favorable change in sales mix to products and services with higher margins. The improved margins in drilling and wireline services in the deepwater resulted in a significant increase in profits in the Gulf of Mexico during 2012 compared to 2011. North America profit before tax in 2012 was negatively impacted by a $33 million charge associated with the information technology expenses and the facility closure, while 2011 profit before tax was impacted by the trade name impairment charge discussed previously.

Latin America

Latin America revenue increased 10% in 2012 compared to 2011. The primary driver was higher activity benefiting our drilling services, artificial lift, completion systems and pressure pumping product lines in Brazil and the Andean region, improved pricing and increased activity in the pressure pumping product line in Argentina and higher land activity in Mexico.

Latin America profit before tax decreased 12% in 2012 compared to 2011. Despite the increase in revenue, profits were negatively impacted by an increase of $85 million in our allowance for doubtful accounts and higher personnel costs. Latin America profit before tax in 2012 was also negatively impacted by a $7 million charge associated with the information technology expenses and the facility closure, while 2011 profit before tax was impacted by the trade name impairment charge discussed previously.

Europe/Africa/Russia Caspian

EARC revenue increased 8% in 2012 compared to 2011. Strong growth was seen in Africa, particularly with drilling systems in Mozambique and Nigeria, completion systems in Nigeria and Angola, wireline services in Nigeria, Uganda and Angola and resumed operations in Libya. Revenue increases in Africa were augmented by increases in our Europe region due primarily to increased wireline services activity in Norway, the U.K. and Eastern

Mediterranean as well as increased drilling fluids activity in the U.K. and Eastern Mediterranean. Revenue also increased in Russia, with sizable growth in our artificial lift, drilling services and drilling fluids product lines.

EARC profit before tax increased 74% in 2012 compared to 2011. A favorable change in sales mix in Russia and Sub Sahara Africa, particularly in Uganda and Angola, as well as increased activity in Mozambique, Nigeria and Libya contributed to improved margins and increased profitability. The activity gains in Europe further increased profitability for 2012. EARC profit before tax in 2012 was negatively impacted by an $11 million charge associated with the information technology expenses and the facility closure. In 2011, EARC profit before tax was negatively impacted by a $70 million charge associated with the cessation of operations due to civil unrest in Libya in addition to the trade name impairment charge discussed previously.

Middle East/Asia Pacific

MEAP revenue increased 15% in 2012 compared to 2011. The increase in this segment was attributable to significant growth for our completion systems, drilling services and drilling fluids product lines in Saudi Arabia, as well as new integrated operations contracts and increased wireline services and upstream chemicals activity in Iraq. In Asia Pacific, increased activity, particularly for completion systems in Australia and pressure pumping in Malaysia and Thailand, was partially offset by reduced activity for pressure pumping and drilling fluids in India.

MEAP profit before tax remained relatively flat in 2012 compared to 2011. While revenue increased, profit before tax was impacted by high operating and third party costs associated with the new integrated operations activities in Iraq and increased personnel costs. In 2012, MEAP profit before tax was also negatively impacted by a $10 million charge associated with the information technology expenses and the facility closure, while 2011 profit before tax was impacted by the trade name impairment charge discussed previously.

Industrial Services

For Industrial Services, revenue increased 7% and profit before tax increased 38% in 2012 compared to 2011. The increase in revenue was primarily driven by increased demand for our process and pipeline business and downstream chemical products in North America. The increase in profit before tax in 2012 compared to 2011 is mainly attributable to the $51 million trade name impairment charge recorded in 2011, which did not recur in 2012. Industrial Services profit before tax in 2012 was negatively impacted by a $2 million charge associated with the information technology expenses and the facility closure.

Costs and Expenses

The table below details certain consolidated statement of income data and as a percentage of revenue.

	2013		2012		2011	
	$	%	$	%	$	%
Revenue	$ 22,364	100%	$ 21,361	100%	$ 19,831	100%
Cost of revenue	18,553	83%	17,356	81%	15,264	77%
Research and engineering	556	2%	497	2%	462	2%
Marketing, general and administrative	1,306	6%	1,316	6%	1,190	6%

Cost of Revenue

Cost of revenue as a percentage of revenue was 83% and 81% for 2013 and 2012, respectively. The increase in cost of revenue as a percentage of revenue was due primarily to lower margins in our pressure pumping product line in North America as a result of the overcapacity in the pressure pumping industry. Additionally, depreciation expense across all segments increased cost of revenue by $160 million in 2013 compared to 2012. In Latin America, lower pricing on the drilling services contract in Brazil led to an increase in cost of revenue relative to revenue. In Europe, reduced pricing and increased start-up costs on a new drilling services contract in Norway decreased margins, as well as an unfavorable change in sales mix. Margins in the Middle East were negatively impacted by third party costs related to our Iraq integrated contracts. Further, cost of revenue was negatively impacted from a disruption to our operations in Iraq in the fourth quarter of 2013. In 2013, margins were favorably impacted by higher incremental profit on revenue in Asia Pacific, and improvement of sales mix in Africa, Russia Caspian and the Gulf of Mexico, as well as, lower provision for doubtful accounts of $25 million.

Cost of revenue as a percentage of revenue was 81% and 77% for 2012 and 2011, respectively. The increase in cost of revenue was due primarily to lower margins in our pressure pumping product line in North America, start-up and third party costs associated with the new integrated operations activities in Iraq, as well as increased amortization expense. In 2012, we recorded charges totaling $85 million to increase our allowance for doubtful accounts in Latin America and a charge of $20 million related to the closure of a chemical manufacturing facility as part of our supply chain cost saving initiative.

Research and Engineering

Research and engineering expenses increased 12% in 2013 compared to 2012. In 2013, we continued to ramp up our research and development activity at our technology centers in Brazil and Saudi Arabia, which resulted in higher personnel and material costs. As a result of our research and development activities in 2013, we commercially launched over 100 new products and services. We are committed to expanding our core services to include critical capabilities and emerging technologies.

Research and engineering expenses increased 8% in 2012 compared to 2011. The increase in research and engineering expenses was driven by increased activity and staffing at our technology centers, which opened in the fourth quarter of 2011. Additionally, research and engineering expenses were impacted by increasing material costs and higher material usage related to research and development activities.

Marketing, General and Administrative

Marketing, general and administrative ("MG&A") expenses decreased 1% in 2013 compared to 2012. MG&A expenses in 2013 decreased as a result of a non-recurring charge recorded in the third quarter of 2012 of $43 million related to the impairment of certain information technology assets as well as the winding down of our worldwide integration efforts subsequent to our acquisition of BJ Services in 2010. The conclusion of our integration efforts resulted in decreased costs related to technology, project management and personnel, and led to improved efficiencies among our global operations and support functions. The reduction in MG&A was largely offset by the loss of $23 million due to the currency devaluation in Venezuela that occurred in the first quarter of 2013, higher salaries and wage costs for personnel, and foreign exchange losses caused by unfavorable movement in exchange rates for foreign currencies against the U.S. Dollar.

MG&A expenses increased 11% in 2012 compared to 2011. The increase in MG&A expenses was primarily due to a charge of $43 million related to the impairment of certain information technology assets. In addition to these costs, the increase in MG&A expenses resulted from ongoing activities to further improve productivity and efficiency through the coordination and integration of our worldwide operations, including software implementations and enhancements, partially offset by decreased personnel costs.

Impairment of Trade Names

In 2011, we recognized a charge of $315 million related to the impairment of certain trade names, the majority of which related to the BJ Services trade name. The impairment of the BJ Services trade name was due to the decision to minimize the use of the BJ Services trade name as part of our overall branding strategy for Baker Hughes.

Interest Expense, net

Interest expense, net of interest income, was $234 million in 2013, an increase of $24 million compared to 2012. The increase in interest expense was primarily due to the reduction of capitalized interest in 2013, which corresponds with the decrease in our capital expenditures.

Interest expense, net of interest income, was $210 million in 2012, a decrease of $11 million compared to 2011. The decrease was primarily due to the repayment of our 5.75% notes in the second quarter of 2011, the early extinguishment in the third quarter of 2011 of our 6.5% senior notes due in November 2013 and the increase in capitalized interest in 2012 associated with the increase in our capital expenditures. The decrease in interest expense was partially offset by the issuance of $750 million 3.2% senior notes in August 2011, the inception of two capital leases in the second and third quarters of 2011 for pumping vessels and increased borrowings under our commercial paper program in 2012.

Loss on Early Extinguishment of Debt

In 2011, we redeemed in full $500 million of debt maturing November 2013 and paid a redemption premium of $63 million. The redemption resulted in a pre-tax loss of $40 million on the early extinguishment of debt, which included the redemption premium and the write off of the remaining original debt issuance costs and debt discount, partially offset by the $25 million gain from the termination of two related interest rate swap agreements.

Income Taxes

Total income tax expense was $612 million, $665 million and $596 million for 2013, 2012 and 2011, respectively. Income tax expense in 2011 includes a $214 million tax benefit associated with the reorganization of certain foreign subsidiaries. Excluding the impact of the reorganization in 2011, our effective tax rate on operating profits in 2013, 2012, and 2011 was 35.7%, 33.6% and 34.6%, respectively. The 2013 effective tax rate is higher than the U.S. statutory income tax rate of 35% due to higher rates on certain international operations, primarily resulting from foreign losses with no tax benefit, and state income taxes partially offset by adjustments to prior years' tax positions. The 2012 and 2011 effective tax rates were lower than the U.S. statutory income tax rate of 35% due to lower rates of tax on certain international operations and adjustments to prior years' tax positions partially offset by state income taxes.

OUTLOOK

This section should be read in conjunction with the factors described in "Part I, Item 1A. Risk Factors" and in the "Forward-Looking Statements" section in this Part II, Item 7, both contained herein. These factors could impact, either positively or negatively, our expectation for: oil and natural gas demand; oil and natural gas prices; exploration and development spending and drilling activity; and production spending.

Our industry is cyclical, and past cycles have been driven primarily by alternating periods of ample supply or shortage of oil and natural gas relative to demand. As an oilfield services company, our revenue is dependent on spending by our customers for oil and natural gas exploration, field development and production. This spending is dependent on a number of factors, including our customers' forecasts of future energy demand, their expectations for future energy prices, their access to resources to develop and produce oil and natural gas, their ability to fund their capital programs and the impact of new government regulations.

Our outlook for exploration and development spending is based upon our expectations for customer spending in the markets in which we operate, and is driven primarily by our perception of industry expectations for oil and natural gas prices and their likely impact on customer capital and operating budgets as well as other factors that could impact the economic return oil and natural gas companies expect for developing oil and natural gas reserves. Our forecasts are based on evaluating a number of external sources as well as our internal estimates. External sources include publications by the IEA, OPEC, Energy Information Administration ("EIA"), and the Organization for Economic Cooperation and Development ("OECD"). We acknowledge that there is a substantial amount of uncertainty regarding these forecasts, thus, while we have internal estimates regarding economic expansion, hydrocarbon demand and overall oilfield activity, we position ourselves to be flexible and responsive to a wide range of potential outcomes.

We consider the primary drivers impacting the 2014 business environment to include the following:

- Worldwide Economic Growth - In general, there is a strong correlation between overall economic growth and global demand for hydrocarbons. The economic outlook for 2014 includes strengthened economic activity but also heightened risks: European countries face concerns over rising sovereign debt levels, China's economy is experiencing a slowdown in growth, and the U.S. continues its moderate pace of recovery. The sovereign debt crisis in Europe has affected the economies of major commodities exporters, including the U.S. and China. Though steps have been taken by governments to maintain growth rates, worsening macroeconomic conditions in the Eurozone remain a threat to the global economic outlook. Since the recession of 2008/2009, China's rapid development and industrialization has been a major factor in driving up worldwide economic growth; however, China's economic growth rates have slowed in recent years to as low as 7.6% in 2013 compared to 2012. For 2014, the International Monetary Fund ("IMF") estimates China's economic growth will be even lower at 7.5% as policymakers refrain from stimulating activity amid inflation concerns. In the U.S., the IMF forecasts 2.8% Gross Domestic Product growth in 2014, a slight increase over 2013, driven by continued strong private demand, and in particular, a recovering housing market. However, this growth may be hampered by any deterioration of the global economy, particularly in China and Europe. Additionally, the Federal Reserve has hinted on the potential withdrawal of quantitative easing by the middle of 2014, which would eliminate approximately $1 trillion in yearly liquidity injections. This could result in interest rate hikes and therefore, increase the cost of borrowing towards new capital projects, including in hydrocarbons.

- Demand for Hydrocarbons - In its January 2014 Oil Market Report, the IEA forecasted global demand for oil to increase by 1.3 million barrels per day ("bpd") in 2014, reaching 92.5 million bpd. This expected increase, mainly driven by countries outside the OECD, should support upstream investment in oil and natural gas production around the world. In addition to the global growth in oil demand, natural gas will continue to play an increasingly important role in meeting the world's energy needs. In its January 2014 Short-Term Energy Outlook, the EIA estimated that industrial demand for natural gas in the U.S. will increase by 0.2 billion cubic feet per day ("bcfd") in 2014, reaching 20.6 bcfd. Overall U.S. natural gas demand is expected to decline by 1.6 bcfd to 69.6 bcfd in 2014 due to lower electric power sector demand and lower heating demand.
- Oil Production - The January 2014 IEA Oil Market Report projected non-OPEC production to grow by 1.7 million bpd in 2014. This increase is largely due to continued production growth from U.S. tight oil formations and Canadian oil sands, fostered by sustained higher oil prices. OPEC's own production target has been unchanged from 30 million bpd, with slight changes possible if there is substantial movement in the oil price. Significant investments are expected to be required to increase production capacity, especially as output from mature fields decline and production rates from early wells at unconventional deposits continue to drop.
- Natural Gas Production - Natural gas production continues to grow worldwide, including in North America where drilling activity has slowed. Despite U.S. natural gas-directed rig counts reaching 18-year lows in recent months, averaging 383 rigs for 2013 which is down from 556 rigs in 2012, natural gas production in the U.S. has increased. In its January 2014 Short-Term Energy Outlook, the EIA estimated that U.S. natural gas production will increase by 2.1% in 2014, from 70.2 bcfd to 71.7 bcfd. Overall, global natural gas output will tend to up in 2014 due to the increased production in the U.S., as well as in the Eastern Hemisphere as high natural gas prices in Europe and Asia should encourage growth.
- Oil Prices - With WTI oil prices trading between $86.68/Bbl and $110.53/Bbl, and Brent trading between $96.79/Bbl and $119.34/Bbl during 2013, most global oil activity will continue to provide adequate returns to encourage incremental investment. Based on oil supply forecasts and modest anticipated economic growth globally, oil prices are expected to remain relatively stable throughout 2014, barring any major macroeconomic changes.
- Natural Gas Prices - With Henry Hub natural gas prices trading between $3.08/mmBtu and $4.52/mmBtu during 2013, and the EIA projecting in its January 2014 Short-term Energy Outlook an average of $3.89/mmBtu in 2014, the economics of most dry natural gas-directed investments in North America will likely continue to be marginal. This is primarily due to the abundant supplies from unconventional plays in North America, including associated gas produced at liquids-rich unconventional plays.

Activity and Spending Outlook for North America - Overall customer spending in North America is expected to increase between 4% and 5% in 2014 compared to 2013, but the average annual rig count is expected to be flat, in part reflecting improved efficiencies in drilling performance. Overall service activity has increased in North America as customers demand robust technologies such as advanced directional drilling, complex completion systems and pressure pumping to develop liquids-rich unconventional plays such as the Eagle Ford and Bakken. Drilling activity in the Gulf of Mexico is expected to increase in 2014, with the addition of 4 or 5 new deepwater exploration rigs. Completions and development activity in the Gulf of Mexico will also continue to grow in 2014. In Canada, overall rig activity in 2014 is expected to be up approximately 5% as compared to 2013.

Activity and Spending Outlook Outside North America - International activity is driven primarily by the oil and gas price environment, which currently provides attractive economic returns in almost every geographic region and is strong enough to support major natural gas export projects. Customers are expected to increase spending to develop new resources and offset declines from existing producing fields, relying on advanced drilling techniques to support exploration and production activities in deepwater, heavy or viscous oils and tight reservoirs. For 2014, we anticipate a 10% increase in international rig activity relative to 2013, with improvements anticipated in all international regions. Areas that are expected to see the largest increases include the Middle East, in particular Saudi Arabia, Iraq, and the Gulf States; and Asia Pacific, with the largest growth expected in Australia.

Around the world, the drivers of oil and gas commercialization have changed. Within Southeast Asia, there is an increased focus on exploration and development of oil and natural gas resources to meet high local demand growth rather than the historic focus on exports. In Africa, traditional growth areas such as Angola and Nigeria are being augmented by new producers such as Ghana, Uganda, Mozambique and Tanzania. Russia is striving to maintain 10 million barrels of oil production per day through 2020 by investing in Eastern Siberia and eventually in technically challenging offshore Arctic deposits. Efforts in Russia at developing tight oil using vertical drilling are already underway, and the government provided support for pilot projects in 2013 featuring more complex horizontal drilling and completions. In natural gas, Australia is leading the expansion of LNG export projects, using offshore gas drilling in the northwest shelf as well as onshore coal-bed methane operations. Large-scale gas pipeline exports from the Caspian region to China and Europe are expected to grow significantly in the next five years, spurring drilling for deeper targets, both onshore and offshore, and increased natural gas process plant capacity for sour gas.

While the development of unconventional oil and natural gas deposits is still in its infancy outside North America, there is a general consensus that unconventional resources will play a growing role in the future of global energy supply. Countries taking active steps to develop their unconventional reserves base include Australia, China, Saudi Arabia and Argentina. However, there is demonstrated interest at ministry and national oil company levels in defining unconventional resource potential in almost all countries with active hydrocarbon industries.

COMPLIANCE

We do business in more than 80 countries, including approximately 19 of the 40 countries having the lowest scores in the Transparency International's Corruption Perception Index survey for 2013, which indicates high levels of corruption. We devote significant resources to the development, maintenance, communication and enforcement of our Business Code of Conduct, our anti-bribery compliance policies, our internal control processes and procedures and other compliance related policies. Notwithstanding the devotion of such resources, and in part as a consequence thereof, from time to time we discover or receive information alleging potential violations of laws and regulations, including the FCPA and our policies, processes and procedures. We conduct timely internal investigations of these potential violations and take appropriate action depending upon the outcome of the investigation.

We anticipate that the devotion of significant resources to compliance-related issues, including the necessity for investigations, will continue to be an aspect of doing business in a number of the countries in which oil and natural gas exploration, development and production take place and in which we conduct operations. Compliance-related issues have limited our ability to do business or have raised the cost of operating in these countries. In order to provide products and services in some of these countries, we may in the future utilize ventures with third parties, sell products to distributors or otherwise modify our business approach in order to improve our ability to conduct our business in accordance with applicable laws and regulations and our Business Code of Conduct.

Our Best-in-Class Global Ethics and Compliance Program ("Compliance Program") is based on (i) our Core Values of Integrity, Performance, Teamwork, Learning and Courage; (ii) the standards contained in our Business Code of Conduct; and (iii) the laws of the countries where we operate. Our Compliance Program is referenced within the Company as "C^2" or "Completely Compliant." The Completely Compliant theme is intended to establish the proper Tone-at-the-Top throughout the Company. Employees are consistently reminded that they play a crucial role in ensuring that the Company always conducts its business ethically, legally and safely.

Highlights of our Compliance Program include the following:

- We have comprehensive internal policies over such areas as facilitating payments; travel, entertainment, gifts and charitable donations connected to non-U.S. government officials; payments to non-U.S. commercial sales representatives; and the use of non-U.S. police or military organizations for security purposes. In addition, we have country-specific guidance for customs standards, visa processing, export and re-export controls, economic sanctions and antiboycott laws.
- We have a comprehensive employee compliance training program covering substantially all employees.
- We have a due diligence procedure for commercial sales, processing and professional agents and an enhanced process for classifying distributors.
- We have a special compliance committee, which is made up of senior officers, that meets no less than once a year to review the oversight reports for all active commercial sales representatives.
- We have continued our reduction of the use of commercial sales representatives and processing agents, including the reduction of customs agents.
- We use technology to monitor and report on compliance matters, including a web-based antiboycott reporting tool and a global trade management software tool.
- We have a program designed to encourage reporting of any ethics or compliance matter without fear of retaliation including a worldwide Business Helpline operated by a third party and currently available toll-free in 150 languages to ensure that our helpline is easily accessible to employees in their own language.
- We have a centralized finance organization including an enterprise-wide accounting system and company-wide policies. In addition, the corporate audit function has incorporated anti-corruption procedures in audits of certain countries. We also conduct FCPA risk assessments and legal audit procedures.
- We continue to work to ensure that we have adequate legal compliance coverage around the world, including the coordination of compliance advice and customized training across all regions and countries where we do business.
- We have a centralized human resources function, including consistent standards for pre-hire screening of employees, the screening of existing employees prior to promoting them to positions where they may be exposed to corruption-related risks, and a uniform policy for new hire training.

LIQUIDITY AND CAPITAL RESOURCES

Our objective in financing our business is to maintain sufficient liquidity, adequate financial resources and financial flexibility in order to fund the requirements of our business. At December 31, 2013, we had cash and cash equivalents of $1.40 billion, of which substantially all was held by foreign subsidiaries. A substantial portion of the cash held by foreign subsidiaries at December 31, 2013 was reinvested in our international operations as our intent is to use this cash to, among other things, fund the operations of our foreign subsidiaries. If we decide at a later date to repatriate those funds to the U.S., we may be required to provide taxes on certain of those funds based on applicable U.S. tax rates net of foreign tax credits. In addition, we have a $2.50 billion committed revolving credit facility with commercial banks and a commercial paper program under which we may issue up to $2.50 billion. The maximum combined borrowing at any time under both the credit facility and the commercial paper program is $2.50 billion. At December 31, 2013, we had commercial paper outstanding of $254 million; therefore, the amount available for borrowing under the facility as of December 31, 2013 was $2.246 billion. We believe that cash on hand, cash flows generated from operations and the available credit facility, including the issuance of commercial paper, will provide sufficient liquidity to manage our global cash needs. In 2013, we used cash to pay for a variety of activities including working capital needs, capital expenditures, repurchase of our common stock and payment of dividends.

Cash Flows

Cash flows provided by (used in) each type of activity were as follows for the years ended December 31:

(In millions)	2013	2012	2011
Operating activities	$ 3,161	$ 1,835	$ 1,507
Investing activities	(1,663)	(2,521)	(1,891)
Financing activities	(1,103)	646	(30)

Operating Activities

Cash flows from operating activities provided $3.16 billion and $1.84 billion for the years ended December 31, 2013 and 2012, respectively. Cash flows from operating activities increased $1.33 billion in 2013 primarily due to the change in net operating assets and liabilities, which used less cash in 2013 compared to 2012.

The main underlying drivers in 2013 compared to 2012 of the changes in operating assets and liabilities are as follows:

- An increase in accounts receivable used cash of $453 million and provided cash of $16 million in 2013 and 2012, respectively. The increase in accounts receivable in 2013 was primarily due to an increase in activity and the corresponding revenue growth partially offset by improved collections as evidenced by a decrease in days sales outstanding (defined as the average number of days our net trade receivables are outstanding based on quarterly revenue).
- An increase in inventory used cash of $120 million and $547 million in 2013 and 2012, respectively, driven by an increase in activity levels partially offset by improved inventory utilization.
- An increase in accounts payable provided $845 million in cash in 2013 and used cash of $94 million in 2012. This increase in accounts payable was primarily due to increased activity and an improvement in our days payable outstanding resulting from vendor management initiatives.
- Accrued employee compensation and other accrued liabilities provided cash of $231 million and used cash of $90 million in 2013 and 2012, respectively. The increase in cash provided in 2013 was primarily due to the change in accrued employee compensation driven by an increase in employee bonus accruals for 2013 compared to 2012 coupled with lower payments for employee bonuses in 2013 compared to 2012. Additionally, the cash improvement for other accrued liabilities resulted from advanced customer payments.

Cash flows from operating activities provided $1.84 billion and $1.51 billion for the year ended December 31, 2012 and 2011, respectively. This increase in cash flows of $328 million is primarily due to the change in net operating assets and liabilities, which used less cash in 2012 compared to 2011.

The main underlying drivers in 2012 compared to 2011 of the changes in operating assets and liabilities are as follows:

- The change in accounts receivable provided cash of $16 million and used cash of $1.02 billion in 2012 and 2011, respectively. The slight change in accounts receivable in 2012 was primarily due to improved collections over the prior year partially offset by an increase in activity. The change in accounts receivable in 2011 was primarily due to an increase in activity as well as an increase in days sales outstanding due to temporary invoicing delays resulting from the implementation of our enterprise wide software system for BJ Services in North America.
- An increase in inventory used cash of $547 million and $641 million in 2012 and 2011, respectively, driven by an increase in activity.
- Accrued employee compensation and other accrued liabilities used cash of $90 million and provided cash of $58 million in 2012 and 2011, respectively. The net change of $148 million was primarily due to an increase in payments related to employee bonuses earned in 2011 but paid in 2012 coupled with lower employee compensation accruals in 2012.
- Income taxes payable used cash of $56 million and $121 million in 2012 and 2011, respectively. The change of $65 million was primarily due to a decrease in income taxes paid in 2012 compared to 2011.
- Other operating items used cash of $213 million and $19 million in 2012 and 2011, respectively. The net change of $194 million was primarily due to an increase in payments for prepaid assets in line with increased activity and an increase in contributions to our pension plans.

Investing Activities

Our principal recurring investing activity is the funding of capital expenditures to ensure that we have the appropriate levels and types of machinery and equipment in place to generate revenue from operations. Expenditures for capital assets totaled $2.09 billion, $2.91 billion and $2.46 billion for 2013, 2012 and 2011, respectively. While the majority of these expenditures were for machinery and equipment, we have continued our spending on new facilities, expansions of existing facilities and other infrastructure projects.

Proceeds from the disposal of assets were $455 million, $389 million and $311 million for 2013, 2012 and 2011, respectively. These disposals related to equipment that was lost-in-hole and property, machinery, and equipment no longer used in operations that was sold throughout the year.

During 2011, we had U.S. Treasury Bills mature resulting in the receipt of proceeds of $250 million.

We routinely evaluate potential acquisitions of businesses that may enhance our current operations or expand our operations into new markets or product lines. We may also from time to time sell business operations that are not considered part of our core business. During 2013, 2012 and 2011, we did not have any significant business acquisitions or dispositions.

Financing Activities

We had net repayments of commercial paper and other short-term debt of $571 million in 2013, and net borrowing of commercial paper and other short-term debt of $847 million and $125 million in 2012 and 2011, respectively. In 2011, we completed a private placement of $750 million 3.2% senior notes that will mature in August 2021, resulting in net proceeds of approximately $742 million after deducting the underwriting discounts and expenses of the offering and used $563 million of the net proceeds to redeem our 6.5% notes in full. The remaining net proceeds from the senior notes were used for general corporate purposes. In addition in 2011, we repaid $250 million of our 5.75% notes that matured.

Total debt outstanding at December 31, 2013 was $4.38 billion, a decrease of $535 million compared to December 31, 2012. The total debt-to-capital (defined as total debt plus equity) ratio was 0.20 at December 31, 2013 and 0.22 at December 31, 2012. We received proceeds of $101 million, $81 million and $183 million in 2013, 2012 and 2011, respectively, from the issuance of common stock through the exercise of stock options and the employee stock purchase plan.

Our Board of Directors has authorized a program to repurchase our common stock from time to time. During 2013, our Board of Directors increased the authorization to purchase our common stock under our share repurchase program by $800 million, for a total remaining authorized amount of $2.0 billion. During the fourth quarter of 2013, we repurchased 6.3 million shares of our common stock at an average price of $55.59 per share, for a total of $350 million. We had authorization remaining to repurchase approximately $1.65 billion in common stock at the end of 2013. During 2012 and 2011, we did not repurchase any shares of common stock.

From January 1, 2014 through February 7, 2014, we repurchased 1.4 million shares of our common stock at an average price of $56.79 per share for a total of $78 million. As of February 7, 2014, we had authorization remaining to purchase approximately $1.57 billion in common stock.

We paid dividends of $267 million, $263 million and $261 million in 2013, 2012 and 2011, respectively.

Available Credit Facility

At December 31, 2013, we had a $2.50 billion committed revolving credit facility with commercial banks that matures in September 2016. This facility contains certain covenants which, among other things, restrict certain merger transactions or the sale of all or substantially all of our assets or a significant subsidiary and limit the amount of subsidiary indebtedness. Upon the occurrence of certain events of default, our obligations under the facility may be accelerated. Such events of default include payment defaults to lenders under the facility, covenant defaults and other customary defaults. At December 31, 2013, we were in compliance with all of the facility's covenants. There were no direct borrowings under the committed credit facility in 2013. We also have a commercial paper program under which we may issue from time to time up to $2.50 billion in commercial paper with maturity of no more than 270 days. The maximum combined borrowing at any point in time under both the commercial paper program and the credit facility is $2.50 billion. At December 31, 2013, we had $254 million of commercial paper outstanding; therefore, the amount available for borrowing under the facility as of December 31, 2013 was $2.246 billion.

If market conditions were to change and our revenue was reduced significantly or operating costs were to increase, our cash flows and liquidity could be reduced. Additionally, it could cause the rating agencies to lower our credit rating. There are no ratings triggers that would accelerate the maturity of any borrowings under our committed credit facility. However, a downgrade in our credit ratings could increase the cost of borrowings under the facility and could also limit or preclude our ability to issue commercial paper. Should this occur, we would seek alternative sources of funding, including borrowing under the facility.

We believe our current credit ratings would allow us to obtain interim financing over and above our existing credit facility for any currently unforeseen significant needs or growth opportunities. We also believe that such interim financings could be funded with subsequent issuances of long-term debt or equity, if necessary.

Cash Requirements

In 2014, we believe cash on hand, cash flows from operating activities and the available credit facility will provide us with sufficient capital resources and liquidity to manage our working capital needs, meet contractual obligations, fund capital expenditures, and support the development of our short-term and long-term operating strategies. If necessary, we may issue commercial paper or other short-term debt to fund cash needs in the U.S. in excess of the cash generated in the U.S.

In 2014, we expect our capital expenditures to be approximately $2.0 billion, excluding any amount related to acquisitions. The expenditures are expected to be used primarily for normal, recurring items necessary to support our business and operations. A significant portion of our capital expenditures can be adjusted and managed by us to match market demand and activity levels. In 2014, we also expect to make interest payments of between $235 million and $255 million, based on debt levels as of December 31, 2013. We anticipate making income tax payments of between $1.0 billion and $1.1 billion in 2014.

We may repurchase our common stock depending on market conditions, applicable legal requirements, our liquidity and other considerations. We anticipate paying dividends of between $263 million and $273 million in 2014; however, the Board of Directors can change the dividend policy at any time.

For all defined benefit, defined contribution and other postretirement plans, we expect to contribute between $385 million and $422 million to these plans in 2014. See Note 10 of the Notes to Consolidated Financial Statements in Item 8 herein for further discussion of our employee benefit plans.

Contractual Obligations

In the table below, we set forth our contractual cash obligations as of December 31, 2013. Certain amounts included in this table are based on our estimates and assumptions about these obligations, including their duration, anticipated actions by third parties and other factors. The contractual cash obligations we will actually pay in future periods may vary from those reflected in the table because the estimates and assumptions are subjective.

	Payments Due by Period				
(In millions)	**Total**	**Less Than 1 Year**	**2 - 3 Years**	**4 - 5 Years**	**More Than 5 Years**
Total debt and capital lease obligations [1]	$ 4,410	$ 499	$ 39	$ 1,024	$ 2,848
Estimated interest payments [2]	3,273	232	455	438	2,148
Operating leases [3]	1,049	405	408	114	122
Purchase obligations [4]	1,672	483	678	343	168
Income tax liabilities for uncertain tax positions [5]	282	119	108	18	37
Other long-term liabilities	194	54	69	11	60
Total [6]	$ 10,880	$ 1,792	$ 1,757	$ 1,948	$ 5,383

(1) Amounts represent the expected cash payments for the principal amounts related to our debt, including outstanding commercial paper of $254 million, and capital lease obligations. Amounts for debt do not include any unamortized discounts or deferred issuance costs. Expected cash payments for interest are excluded from these amounts.

(2) Amounts represent the expected cash payments for interest on our long-term debt and capital lease obligations.
(3) Represents future minimum payments under noncancelable operating leases with initial or remaining terms of one year or more. We enter into operating leases, some of which include renewal options. We have excluded renewal options from the table above unless it is anticipated that we will exercise such renewals.
(4) Purchase obligations include capital improvements as well as agreements to purchase goods or services that are enforceable and legally binding and that specify all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction.
(5) The estimated income tax liabilities for uncertain tax positions will be settled as a result of expiring statutes, audit activity, competent authority proceedings related to transfer pricing, or final decisions in matters that are the subject of litigation in various taxing jurisdictions in which we operate. The timing of any particular settlement will depend on the length of the tax audit and related appeals process, if any, or an expiration of a statute. If a liability is settled due to a statute expiring or a favorable audit result, the settlement of the tax liability would not result in a cash payment.
(6) Does not include obligations for pension and other postretirement benefits for which we expect to make employer contributions between $115 million and $129 million in 2014.

Off-Balance Sheet Arrangements

In the normal course of business with customers, vendors and others, we have entered into off-balance sheet arrangements, such as surety bonds for performance, letters of credit and other bank issued guarantees, which totaled approximately $1.5 billion at December 31, 2013. It is not practicable to estimate the fair value of these financial instruments. None of the off-balance sheet arrangements either has, or is likely to have, a material effect on our consolidated financial statements.

Other than normal operating leases, we do not have any off-balance sheet financing arrangements such as securitization agreements, liquidity trust vehicles, synthetic leases or special purpose entities. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such financing arrangements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenue and expenses and related disclosures as well as disclosures about any contingent assets and liabilities. We base these estimates and judgments on historical experience and other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects are subject to uncertainty, and accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the business environment in which we operate changes.

We have defined a critical accounting estimate as one that is both important to the portrayal of either our financial condition or results of operations and requires us to make difficult, subjective or complex judgments or estimates about matters that are uncertain. The Audit/Ethics Committee of our Board of Directors has reviewed our critical accounting estimates and the disclosure presented below. During the past three fiscal years, we have not made any material changes in the methodology used to establish the critical accounting estimates, and we believe that the following are the critical accounting estimates used in the preparation of our consolidated financial statements. There are other items within our consolidated financial statements that require estimation and judgment but they are not deemed critical as defined above.

Allowance for Doubtful Accounts

The determination of the collectability of amounts due from our customers requires us to make judgments and estimates regarding our customers' ability to pay amounts due us in order to determine the amount of valuation allowances required for doubtful accounts. We monitor our customers' payment history and current credit worthiness to determine that collectability is reasonably assured. We also consider the overall business climate in which our customers operate. Provisions for doubtful accounts are recorded when it becomes evident that the customer will not make the required payments at either contractual due dates or in the future. At December 31, 2013 and 2012, the allowance for doubtful accounts totaled $238 million, or 4%, and $308 million, or 6%, of total gross accounts receivable, respectively. We believe that our allowance for doubtful accounts is adequate to cover potential bad debt losses under current conditions; however, uncertainties regarding changes in the financial condition of our customers, either adverse or positive, could impact the amount and timing of any additional provisions for doubtful accounts that may be required. A five percent change in the allowance for doubtful accounts would have had an impact on income before income taxes of approximately $12 million in 2013.

Inventory Reserves

Inventory is a significant component of current assets and is stated at the lower of cost or market. This requires us to record provisions and maintain reserves for excess, slow moving and obsolete inventory. To determine these reserve amounts, we regularly review inventory quantities on hand and compare them to estimates of future product demand, market conditions, production requirements and technological developments. These estimates and forecasts inherently include uncertainties and require us to make judgments regarding potential future outcomes. At December 31, 2013 and 2012, inventory reserves totaled $382 million, or 9%, and $346 million, or 8%, of gross inventory, respectively. We believe that our reserves are adequate to properly value potential excess, slow moving and obsolete inventory under current conditions. Significant or unanticipated changes to our estimates and forecasts could impact the amount and timing of any additional provisions for excess, slow moving or obsolete inventory that may be required. A five percent change in this inventory reserve balance would have had an impact on income before income taxes of approximately $19 million in 2013.

Goodwill and Other Long-Lived Assets

The purchase price of acquired businesses is allocated to its identifiable assets and liabilities based upon estimated fair values as of the acquisition date. Goodwill is the excess of the purchase price over the fair value of tangible and identifiable intangible assets and liabilities acquired in a business acquisition. Our goodwill at December 31, 2013 totaled $5.97 billion. We perform an annual test of goodwill for impairment as of October 1 of each year for each of our reporting units, which are generally based on our organizational and reporting structure. In determining the carrying amount of reporting units, corporate and other assets and liabilities are allocated to the extent that they relate to the operations of those reporting units. These tests include both qualitative and quantitative factors. When necessary, we calculate the fair value of a reporting unit using various valuation techniques, including a market approach, a comparable transactions approach and discounted cash flow ("DCF") methodology. The market approach and comparable transactions approach provide value indications for a company through a comparison with guideline public companies or guideline transactions, respectively. Both entail selecting relevant financial information of the subject company, and capitalizing those amounts using valuation multiples that are based on empirical market observations. The DCF methodology includes, but is not limited to, assumptions regarding matters such as discount rates, anticipated growth rates, expected profitability rates and the timing of expected future cash flows. The results of the 2013 test indicated that there were no impairments of goodwill. Unanticipated changes, including even small revisions, to these assumptions could require a provision for impairment in a future period. Given the nature of these evaluations and their application to specific assets and time-frames, it is not possible to reasonably quantify the impact of changes in these assumptions.

Long-lived assets, which include property and equipment, intangible assets other than goodwill, and certain other assets, comprise a significant amount of our total assets. We review the carrying values of these assets for impairment periodically, and at least annually for certain intangible assets or whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. An impairment loss is recorded in the period in which it is determined that the carrying amount is not recoverable. This requires us to make judgments regarding long-term forecasts of future revenue and costs and cash flows related to the assets subject to review. These forecasts are uncertain in that they require assumptions about demand for our products and services, future market conditions and technological developments.

Income Taxes

The liability method is used for determining our income tax provisions, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates. Under this method, the amounts of deferred tax liabilities and assets at the end of each period are determined using the tax rate expected to be in effect when taxes are actually paid or recovered. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In determining the need for valuation allowances, we have considered and made judgments and estimates regarding estimated future taxable income and ongoing prudent and feasible tax planning strategies. These estimates and judgments include some degree of uncertainty and changes in these estimates and assumptions could require us to adjust the valuation allowances for our deferred tax assets. Historically, changes to valuation allowances have been caused by major changes in the business cycle in certain countries and changes in local country law. The ultimate realization of the deferred tax assets depends on the generation of sufficient taxable income in the applicable taxing jurisdictions.

We operate in more than 80 countries under many legal forms. As a result, we are subject to the jurisdiction of numerous domestic and foreign tax authorities, as well as to tax agreements and treaties among these governments. Our operations in these different jurisdictions are taxed on various bases: actual income before taxes, deemed profits (which are generally determined using a percentage of revenue rather than profits) and withholding taxes based on revenue. Determination of taxable income in any jurisdiction requires the interpretation of the related tax laws and regulations and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of deductions, permissible revenue recognition methods under the tax law and the sources and character of income and tax credits. Changes in tax laws, regulations, agreements and treaties, foreign currency exchange restrictions or our level of operations or profitability in each taxing jurisdiction could have an impact on the amount of income taxes that we provide during any given year.

Our tax filings for various periods are subject to audit by the tax authorities in most jurisdictions where we conduct business. These audits may result in assessments of additional taxes that are resolved with the authorities or through the courts. We believe these assessments may occasionally be based on erroneous and even arbitrary interpretations of local tax law. Resolution of these situations inevitably includes some degree of uncertainty; accordingly, we provide taxes only for the amounts we believe will ultimately result from these proceedings. The resulting change to our tax liability, if any, is dependent on numerous factors including, among others, the amount and nature of additional taxes potentially asserted by local tax authorities; the willingness of local tax authorities to negotiate a fair settlement through an administrative process; the impartiality of the local courts; the number of countries in which we do business; and the potential for changes in the tax paid to one country to either produce, or fail to produce, an offsetting tax change in other countries. Our experience has been that the estimates and assumptions we have used to provide for future tax assessments have proven to be appropriate. However, past experience is only a guide, and the potential exists that the tax resulting from the resolution of current and potential future tax controversies may differ materially from the amount accrued.

In addition to the aforementioned assessments that have been received from various tax authorities, we also provide for taxes for uncertain tax positions where formal assessments have not been received. The determination of these liabilities requires the use of estimates and assumptions regarding future events. Once established, we adjust these amounts only when more information is available or when a future event occurs necessitating a change to the reserves such as changes in the facts or law, judicial decisions regarding the application of existing law or a favorable audit outcome. We believe that the resolution of tax matters will not have a material effect on the consolidated financial condition of the Company, although a resolution could have a material impact on our consolidated statements of income for a particular period and on our effective tax rate for any period in which such resolution occurs.

Pensions and Postretirement Benefit Obligations

Pensions and postretirement benefit obligations and the related expenses are calculated using actuarial models and methods. This involves the use of two critical assumptions, the discount rate and the expected rate of return on assets, both of which are important elements in determining pension expense and in measuring plan liabilities. We evaluate these critical assumptions at least annually, and as necessary, we utilize third party actuarial firms to assist us. Although considered less critical, other assumptions used in determining benefit obligations and related expenses, such as demographic factors like retirement age, mortality and turnover, are also evaluated periodically and are updated to reflect our actual and expected experience.

The discount rate enables us to determine expected future cash flows at a present value on the measurement date. The development of the discount rate for our largest plans was based on a bond matching model whereby the cash flows underlying the projected benefit obligation are matched against a yield curve constructed from a bond portfolio of high-quality, fixed-income securities. Use of a lower discount rate would increase the present value of benefit obligations and increase pension expense. We used a weighted average discount rate of 4.0% in 2013, 4.6% in 2012 and 5.2% in 2011 to determine pension expense. A 50 basis point reduction in the weighted average discount rate would have increased pension expense and the projected benefit obligation of our principal pension plans by approximately $8 million and $92 million, respectively, in 2013.

To determine the expected rate of return on plan assets, we consider the current and target asset allocations, as well as historical and expected future returns on various categories of plan assets. A lower rate of return would decrease plan assets which results in higher pension expense. We assumed a weighted average expected rate of return on our plan assets of 6.9% in 2013, 7.0% in 2012 and 7.2% in 2011. A 50 basis point reduction in the weighted average expected rate of return on assets of our principal pension plans would have increased pension expense by approximately $6 million in 2013.

NEW ACCOUNTING STANDARDS UPDATES

In February 2013, the FASB issued ASU No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*. This ASU requires entities to present separately, among other items, the amount of the change that is due to reclassifications, and the amount that is due to current period other comprehensive income. We adopted the new presentation requirements in the notes to our financial statements in the first quarter of 2013. See Note 12 of the Notes to Consolidated Financial Statements in Item 8 herein for additional information.

In July 2012, the Financial Accounting Standards Board ("FASB") issued an update to ASC 350, *Intangibles - Goodwill and Other*. This ASU amends the guidance in ASC 350-30 on testing indefinite-lived intangible assets for impairment. The revised guidance permits an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired as a basis for determining whether it is necessary to perform the quantitative impairment test. The ASU is effective for impairment tests performed for fiscal years beginning after September 15, 2012. We adopted this ASU for our 2013 impairment testing and it did not have a material impact on our consolidated financial statements.

RELATED PARTY TRANSACTIONS

There were no significant related party transactions during the three years ended December 31, 2013.

FORWARD-LOOKING STATEMENTS

This Form 10-K, including MD&A and certain statements in the Notes to Consolidated Financial Statements, includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act (each a “forward-looking statement”). The words “anticipate,” “believe,” “ensure,” “expect,” “if,” “intend,” “estimate,” “probable,” “project,” “forecasts,” “predict,” “outlook,” “aim,” “will,” “could,” “should,” “would,” “potential,” “may,” “likely” and similar expressions, and the negative thereof, are intended to identify forward-looking statements. Our forward-looking statements are based on assumptions that we believe to be reasonable but that may not prove to be accurate. The statements do not include the potential impact of future transactions, such as an acquisition, disposition, merger, joint venture or other transaction that could occur. We undertake no obligation to publicly update or revise any forward-looking statement. Our expectations regarding our business outlook, including changes in revenue, pricing, capital spending, profitability, strategies for our operations, impact of any common stock repurchases, oil and natural gas market conditions, the business plans of our customers, market share and contract terms, costs and availability of resources, legal, economic and regulatory conditions, and environmental matters are only our forecasts regarding these matters.

All of our forward-looking information is subject to risks and uncertainties that could cause actual results to differ materially from the results expected. Although it is not possible to identify all factors, these risks and uncertainties include the risk factors and the timing of any of those risk factors identified in Item 1A. Risk Factors and those set forth from time to time in our filings with the SEC. These documents are available through our website or through the SEC’s Electronic Data Gathering and Analysis Retrieval system (“EDGAR”) at http://www.sec.gov.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to certain market risks that are inherent in our financial instruments and arise from changes in interest rates and foreign currency exchange rates. We may enter into derivative financial instrument transactions to manage or reduce market risk but do not enter into derivative financial instrument transactions for speculative purposes. A discussion of our primary market risk exposure in financial instruments is presented below.

INTEREST RATE RISK

We have debt in fixed and floating rate instruments. We are subject to interest rate risk on our debt and investment portfolio. We maintain an interest rate risk management strategy which primarily uses a mix of fixed and variable rate debt that is intended to mitigate the risk exposure to changes in interest rates in the aggregate. We may use interest rate swaps to manage the economic effect of fixed rate obligations associated with certain debt. There were no outstanding interest rate swap agreements as of December 31, 2013 or 2012.

We had fixed rate long-term debt, including capital lease obligations, aggregating $3.9 billion and $3.8 billion at December 31, 2013 and 2012, respectively. The following table sets forth our fixed rate long-term debt and the related weighted average interest rates by expected maturity dates as of December 31, 2013 and 2012.

(In millions)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
As of December 31, 2013								
Long-term debt [1] [2]	$ —	$ —	$ 21	$ 17	$ 11	$ 1,013	$ 2,849	$3,911
Weighted average interest rates	—	—	13.68%	17.71%	17.47%	7.41%	5.36%	6.02%
As of December 31, 2012								
Long-term debt [1] [2]	$ —	$ —	$ —	$ —	$ —	$ 1,000	$ 2,800	$3,800
Weighted average interest rates	—	—	—	—	—	7.28%	5.17%	5.72%

[1] Amounts do not include any unamortized discounts or deferred issuance costs on our fixed rate long-term debt.

[2] Fair market value of our fixed rate long-term debt was $4.36 billion at December 31, 2013 and $4.68 billion at December 31, 2012.

FOREIGN CURRENCY EXCHANGE RISK

We conduct our operations around the world in a number of different currencies, and we are exposed to market risks resulting from fluctuations in foreign currency exchange rates. Many of our significant foreign subsidiaries have designated the local currency as their functional currency. As such, future earnings are subject to change due to fluctuations in foreign currency exchange rates when transactions are denominated in currencies other than our functional currencies. To minimize the need for foreign currency forward contracts to hedge this exposure, our objective is to manage foreign currency exposure by maintaining a minimal consolidated net asset or net liability position in a currency other than the functional currency.

At December 31, 2013 and 2012, we had outstanding foreign currency forward contracts with notional amounts aggregating $486 million and $207 million, respectively, to hedge exposure to currency fluctuations in various foreign currencies. The notional amounts of our foreign currency forward contracts do not generally represent amounts exchanged by the parties and, thus are not a measure of the cash requirements related to these contracts or of any possible loss exposure. The amounts actually exchanged are calculated by reference to the notional amounts and by other terms of the derivative contracts, such as exchange rates. Based on quoted market prices as of December 31, 2013 and 2012 for contracts with similar terms and maturity dates, we recorded a gain of $2 million and a loss of $1 million, respectively, to adjust these foreign currency forward contracts to their fair market value. These gains and losses offset designated foreign currency exchange gains and losses resulting from the underlying exposures and are included in MG&A expenses in the consolidated statements of income.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over our financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Our 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.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we assessed the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, our principal executive officer and principal financial officer concluded that our internal control over financial reporting was effective as of December 31, 2013. This conclusion is based on the recognition that there are inherent limitations in all systems of internal control. Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. 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.

Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting.

/s/ MARTIN S. CRAIGHEAD
Martin S. Craighead
Chairman and
Chief Executive Officer

/s/ PETER A. RAGAUSS
Peter A. Ragauss
Senior Vice President and
Chief Financial Officer

/s/ ALAN J. KEIFER
Alan J. Keifer
Vice President and
Controller

Houston, Texas
February 12, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Baker Hughes Incorporated
Houston, Texas

We have audited the accompanying consolidated balance sheets of Baker Hughes Incorporated and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included, financial statement schedule II, valuation and qualifying accounts, listed in the Index at Item 15. We also have audited the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and financial statement schedule and an opinion on the Company's internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Baker Hughes Incorporated and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control — Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
February 12, 2014

BAKER HUGHES INCORPORATED
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
(In millions, except per share amounts)	**2013**	**2012**	**2011**
Revenue:			
Sales	$ 7,594	$ 7,274	$ 6,382
Services	14,770	14,087	13,449
Total revenue	22,364	21,361	19,831
Costs and expenses:			
Cost of sales	5,932	5,758	5,122
Cost of services	12,621	11,598	10,142
Research and engineering	556	497	462
Marketing, general and administrative	1,306	1,316	1,190
Impairment of trade names	—	—	315
Total costs and expenses	20,415	19,169	17,231
Operating income	1,949	2,192	2,600
Interest expense, net	(234)	(210)	(221)
Loss on early extinguishment of debt	—	—	(40)
Income before income taxes	1,715	1,982	2,339
Income taxes	(612)	(665)	(596)
Net income	1,103	1,317	1,743
Net income attributable to noncontrolling interests	(7)	(6)	(4)
Net income attributable to Baker Hughes	$ 1,096	$ 1,311	$ 1,739
Basic earnings per share attributable to Baker Hughes	$ 2.47	$ 2.98	$ 3.99
Diluted earnings per share attributable to Baker Hughes	$ 2.47	$ 2.97	$ 3.97

See Notes to Consolidated Financial Statements

BAKER HUGHES INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	Year Ended December 31,		
(In millions)	**2013**	**2012**	**2011**
Net income	$ 1,103	$ 1,317	$ 1,743
Other comprehensive (loss) income:			
Foreign currency translation adjustments during the period	(61)	78	(44)
Pension and other postretirement benefits, net of tax (2013 - $(23); 2012 - $(13); 2011 - $44)	33	1	(92)
Other comprehensive (loss) income	(28)	79	(136)
Comprehensive income	1,075	1,396	1,607
Comprehensive income attributable to noncontrolling interests	(7)	(6)	(3)
Comprehensive income attributable to Baker Hughes	$ 1,068	$ 1,390	$ 1,604

See Notes to Consolidated Financial Statements

BAKER HUGHES INCORPORATED
CONSOLIDATED BALANCE SHEETS

(In millions, except par value)	December 31, 2013	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,399	$ 1,015
Accounts receivable - less allowance for doubtful accounts (2013 - $238; 2012 - $308)	5,138	4,815
Inventories, net	3,884	3,781
Deferred income taxes	380	266
Other current assets	494	540
Total current assets	11,295	10,417
Property, plant and equipment - less accumulated depreciation (2013 - $7,219; 2012 - $6,315)	9,076	8,707
Goodwill	5,966	5,958
Intangible assets, net	883	993
Other assets	714	614
Total assets	$ 27,934	$ 26,689
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable	$ 2,574	$ 1,737
Short-term debt and current portion of long-term debt	499	1,079
Accrued employee compensation	778	646
Income taxes payable	213	226
Other accrued liabilities	514	436
Total current liabilities	4,578	4,124
Long-term debt	3,882	3,837
Deferred income taxes and other tax liabilities	821	745
Liabilities for pensions and other postretirement benefits	583	579
Other liabilities	158	136
Commitments and contingencies		
Equity:		
Common stock, one dollar par value (shares authorized - 750; issued and outstanding: 2013 - 438; 2012 - 441)	438	441
Capital in excess of par value	7,341	7,495
Retained earnings	10,438	9,609
Accumulated other comprehensive loss	(504)	(476)
Baker Hughes stockholders' equity	17,713	17,069
Noncontrolling interests	199	199
Total equity	17,912	17,268
Total liabilities and equity	$ 27,934	$ 26,689

See Notes to Consolidated Financial Statements

BAKER HUGHES INCORPORATED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(In millions, except per share amounts)	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interests	Total
Balance at December 31, 2010	$ 432	$ 7,005	$ 7,083	$ (420)	$ 186	$ 14,286
Comprehensive income:						
Net income			1,739		4	1,743
Other comprehensive loss				(135)	(1)	(136)
Activity related to stock plans	5	179				184
Stock-based compensation cost		108				108
Cash dividends ($0.60 per share)			(261)			(261)
Net activity related to noncontrolling interests		11			29	40
Balance at December 31, 2011	$ 437	$ 7,303	$ 8,561	$ (555)	$ 218	$ 15,964
Comprehensive income:						
Net income			1,311		6	1,317
Other comprehensive income				79		79
Activity related to stock plans	4	55				59
Stock-based compensation cost		115				115
Cash dividends ($0.60 per share)			(263)			(263)
Net activity related to noncontrolling interests		22			(25)	(3)
Balance at December 31, 2012	$ 441	$ 7,495	$ 9,609	$ (476)	$ 199	$ 17,268
Comprehensive income:						
Net income			1,096		7	1,103
Other comprehensive loss				(28)		(28)
Activity related to stock plans	3	75				78
Repurchase and retirement of common stock	(6)	(344)				(350)
Stock-based compensation cost		115				115
Cash dividends ($0.60 per share)			(267)			(267)
Net activity related to noncontrolling interests					(7)	(7)
Balance at December 31, 2013	$ 438	$ 7,341	$ 10,438	$ (504)	$ 199	$ 17,912

See Notes to Consolidated Financial Statements

BAKER HUGHES INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
(In millions)	**2013**	**2012**	**2011**
Cash flows from operating activities:			
Net income	$ 1,103	$ 1,317	$ 1,743
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	1,698	1,568	1,321
Provision (benefit) for deferred income taxes	1	(114)	(492)
Gain on disposal of assets	(275)	(222)	(179)
Stock-based compensation cost	115	115	108
Provision for doubtful accounts	75	100	84
Impairment of trade names	—	—	315
Loss on impairment of assets	—	55	—
Loss on early extinguishment of debt	—	—	40
Changes in operating assets and liabilities:			
Accounts receivable	(453)	16	(1,024)
Inventories	(120)	(547)	(641)
Accounts payable	845	(94)	314
Accrued employee compensation and other accrued liabilities	231	(90)	58
Income taxes payable	(31)	(56)	(121)
Other operating items, net	(28)	(213)	(19)
Net cash flows provided by operating activities	3,161	1,835	1,507
Cash flows from investing activities:			
Expenditures for capital assets	(2,085)	(2,910)	(2,461)
Proceeds from disposal of assets	455	389	311
Proceeds from maturities of short-term investments	—	—	250
Other investing items, net	(33)	—	9
Net cash flows used in investing activities	(1,663)	(2,521)	(1,891)
Cash flows from financing activities:			
Net (repayments) proceeds of commercial paper borrowings and other debt with three months or less original maturity	(650)	764	125
Repayment of short-term debt with greater than three months original maturity	(163)	(92)	—
Proceeds of short-term debt with greater than three months original maturity	242	175	—
Proceeds of long-term debt	—	—	742
Repayment of long-term debt	—	—	(813)
Repurchase of common stock	(350)	—	—
Proceeds from issuance of common stock	101	81	183
Dividends paid	(267)	(263)	(261)
Other financing items, net	(16)	(19)	(6)
Net cash flows (used in) provided by financing activities	(1,103)	646	(30)
Effect of foreign exchange rate changes on cash and cash equivalents	(11)	5	8
Decrease in cash and cash equivalents	384	(35)	(406)
Cash and cash equivalents, beginning of period	1,015	1,050	1,456
Cash and cash equivalents, end of period	$ 1,399	$ 1,015	$ 1,050
Supplemental cash flows disclosures:			
Income taxes paid, net of refunds	$ 651	$ 941	$ 1,192
Interest paid	$ 247	$ 241	$ 237
Supplemental disclosure of noncash investing activities:			
Capital expenditures included in accounts payable	$ 142	$ 140	$ 111

See Notes to Consolidated Financial Statements

Baker Hughes Incorporated
Notes to Consolidated Financial Statements

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations

Baker Hughes Incorporated ("Baker Hughes," "Company," "we," "our," or "us,") is a leading supplier of oilfield services, products, technology and systems used for drilling, formation evaluation, completion and production, pressure pumping, and reservoir development in the worldwide oil and natural gas industry. We also provide products and services for other businesses, including downstream chemicals, and process and pipeline industries.

Basis of Presentation

The consolidated financial statements include the accounts of Baker Hughes and all of our subsidiaries where we exercise control. For investments in subsidiaries that are not wholly-owned, but where we exercise control, the equity held by the minority owners and their portions of net income (loss) are reflected as noncontrolling interests. Investments over which we have the ability to exercise significant influence over operating and financial policies, but do not hold a controlling interest, are accounted for using the equity method of accounting. All significant intercompany accounts and transactions have been eliminated in consolidation. In the Notes to Consolidated Financial Statements, all dollar and share amounts in tabulations are in millions of dollars and shares, respectively, unless otherwise indicated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("U.S.") requires management to make estimates and judgments that affect the reported amounts of assets and liabilities, 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 base our estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty, and accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as our operating environment changes. While we believe that the estimates and assumptions used in the preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates. Estimates are used for, but are not limited to, determining the following: allowance for doubtful accounts and inventory valuation reserves; recoverability of long-lived assets; useful lives used in depreciation and amortization; income taxes and related valuation allowances; accruals for contingencies and actuarial assumptions to determine costs and liabilities related to employee benefit plans; stock-based compensation and fair value of assets acquired and liabilities assumed in acquisitions.

Revenue Recognition

Our products and services are sold based upon purchase orders, contracts or other agreements with the customer that include fixed or determinable prices and that do not include right of return or other similar 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 for these products upon delivery, when title passes, when collectability is reasonably assured and there are no further significant obligations for future performance. Provisions for estimated warranty returns or similar types of items are made at the time the related revenue is recognized. Revenue for services is recognized as the services are rendered and when collectability is reasonably assured. Rates for services are typically priced on a per day, per meter, per man hour or similar basis. In certain situations, revenue is generated from transactions that may include multiple products and services under one contract or agreement and which may be delivered to the customer over an extended period of time. Revenue from these arrangements is recognized in accordance with the above criteria and as each item or service is delivered based on their relative fair value.

Research and Engineering

Research and engineering expenses are expensed as incurred and include costs associated with the research and development of new products and services and costs associated with sustaining engineering of existing products and services. Costs for research and development of new products and services were $370 million, $337 million and $324 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Cash, Cash Equivalents and Short-term Investments

Cash equivalents include only those investments with an original maturity of three months or less. Short-term investments have an original maturity of greater than three months but less than one year. We maintain cash deposits with financial institutions that may exceed federally insured limits. We monitor the credit ratings and our concentration of risk with these financial institutions on a continuing basis to safeguard our cash deposits.

Allowance for Doubtful Accounts

We establish an allowance for doubtful accounts based on various factors including historical experience, current aging status of the customer accounts, and the payment history and financial condition of our customers. Provisions for doubtful accounts are recorded when it becomes evident that the customer will not make the required payments at either contractual due dates or in the future. Provision for doubtful accounts recorded in cost of sales was $75 million, $100 million and $84 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Concentration of Credit Risk

We grant credit to our customers, which operate primarily in the oil and natural gas industry. Although this concentration could affect our overall exposure to credit risk, we believe that our risk is minimized because the majority of our business is conducted with major companies many of which are geographically diverse, thus spreading the credit risk. To manage this risk, we perform periodic credit evaluations of our customers' financial condition, including monitoring our customers' payment history and current credit worthiness. We do not generally require collateral in support of our trade receivables, but we may require payment in advance or security in the form of a letter of credit or bank guarantee. During 2013, 2012 and 2011, no individual customer accounted for more than 10% of our consolidated revenue.

Inventories

Inventories are stated at the lower of cost or market. Cost is determined using the first-in, first-out ("FIFO") method or the average cost method, which approximates FIFO, and includes the cost of materials, labor and manufacturing overhead. As necessary, we record provisions and maintain reserves for excess, slow moving and obsolete inventory. To determine these reserve amounts, we regularly review inventory quantities on hand and compare them to estimates of future product demand, market conditions, production requirements and technological developments.

Property, Plant and Equipment and Accumulated Depreciation

Property, plant and equipment ("PP&E") is stated at cost less accumulated depreciation, which is generally provided by using the straight-line method over the estimated useful lives of the individual assets. Significant improvements and betterments are capitalized if they extend the useful life of the asset. We manufacture a substantial portion of our tools and equipment and the cost of these items, which includes direct and indirect manufacturing costs, is capitalized and carried in inventory until it is completed. When complete, the cost is reflected in capital expenditures and is classified as machinery, equipment and other in PP&E. Maintenance and repairs are charged to expense as incurred. Upon sale or other disposition, the applicable amounts of asset cost and accumulated depreciation are removed from the balance sheet and the net amount, less proceeds from disposal, is charged or credited to income. The capitalized costs of computer software developed or purchased for internal use are classified in machinery, equipment and other.

Goodwill, Intangible Assets and Amortization

Goodwill is the excess of the consideration transferred over the fair value of the tangible and identifiable intangible assets and liabilities recognized. Goodwill and intangible assets with indefinite lives are not amortized. Intangible assets with finite useful lives are amortized on a basis that reflects the pattern in which the economic benefits of the intangible assets are realized, which is generally on a straight-line basis over the asset's estimated useful life.

Impairment of PP&E, Intangibles, Other Long-lived Assets and Goodwill

We review PP&E, intangible assets and certain other long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable and at least annually for certain intangible assets. The determination of recoverability is made based upon the estimated undiscounted future net cash flows. The amount of impairment loss, if any, is determined by comparing the fair value, as determined by a discounted cash flow analysis, with the carrying value of the related assets.

We perform an annual impairment test of goodwill for each of our reporting units as of October 1, or more frequently if circumstances indicate that an impairment may exist. Our reporting units are based on our organizational and reporting structure. Corporate and other assets and liabilities are allocated to the reporting units to the extent that they relate to the operations of those reporting units in determining their carrying amount. The determination of impairment is made by comparing the carrying amount of each reporting unit with its fair value, which is generally calculated using a combination of market, comparable transaction and discounted cash flow approaches.

Income Taxes

We use the liability method in determining our provision and liabilities for our income taxes, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates. Deferred tax liabilities and assets, which are computed on the estimated income tax effect of temporary differences between financial and tax bases in assets and liabilities, are determined using the tax rate expected to be in effect when taxes are actually paid or recovered. A valuation allowance to reduce deferred tax assets is established when it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We intend to indefinitely reinvest certain earnings of our foreign subsidiaries in operations outside the U.S., and accordingly, we have not provided for U.S. income taxes on such earnings. We do provide for the U.S. and additional non-U.S. taxes on earnings anticipated to be repatriated from our non-U.S. subsidiaries.

Our tax filings for various periods are subject to audit by tax authorities in most jurisdictions where we conduct business. These audits may result in assessments of additional taxes that are resolved with the authorities or through the courts. We have provided for the amounts we believe will ultimately result from these proceedings. In addition to the assessments that have been received from various tax authorities, we also provide for taxes for uncertain tax positions where formal assessments have not been received. We classify interest and penalties related to uncertain tax positions as income taxes in our financial statements.

Environmental Matters

Estimated remediation costs are accrued using currently available facts, existing environmental permits, technology and enacted laws and regulations. For sites where we are primarily responsible for the remediation, our cost estimates are developed based on internal evaluations and are not discounted. Accruals are recorded when it is probable that we will be obligated to pay for environmental site evaluation, remediation or related activities, and such costs can be reasonably estimated. As additional information becomes available, accruals are adjusted to reflect current cost estimates. Ongoing environmental compliance costs, such as obtaining environmental permits, installation of pollution control equipment and waste disposal are expensed as incurred. Where we have been identified as a potentially responsible party in a U.S. federal or state Comprehensive Environmental Response, Compensation and Liability Act ("Superfund") site, we accrue our share of the estimated remediation costs of the site. This share is based on the ratio of the estimated volume of waste we contributed to the site to the total volume of waste disposed at the site.

Foreign Currency

A number of our significant foreign subsidiaries have designated the local currency as their functional currency and, as such, gains and losses resulting from balance sheet translation of foreign operations are included as a separate component of accumulated other comprehensive loss within stockholders' equity. Gains and losses from foreign currency transactions, such as those resulting from the settlement of receivables or payables in the non-functional currency, are included in marketing, general and administrative ("MG&A") expenses in the consolidated statements of income as incurred. For those foreign subsidiaries that have designated the U.S. Dollar as the functional currency, monetary assets and liabilities are remeasured at period-end exchange rates, and nonmonetary items are remeasured at historical exchange rates. Gains and losses resulting from this balance sheet remeasurement are also included in MG&A expenses in the consolidated statements of income as incurred.

In February 2013, Venezuela's currency was devalued from the prior exchange rate of 4.3 Bolivars Fuertes per U.S. Dollar to 6.3 Bolivars Fuertes per U.S. Dollar, which applies to our local currency denominated balances. The impact of this devaluation was a loss of $23 million that was recorded in marketing, general and administrative expense in the first quarter of 2013.

Financial Instruments

Our financial instruments include cash and cash equivalents, accounts receivable, accounts payable, debt, and derivative financial instruments. Except for debt, the estimated fair value of our financial instruments at December 31, 2013 and 2012 approximates their carrying value as reflected in our consolidated balance sheets. For further information on the fair value of our debt, see Note 8. Indebtedness.

We monitor our exposure to various business risks including commodity prices, foreign currency exchange rates and interest rates and regularly use derivative financial instruments to manage these risks. Our policies do not permit the use of derivative financial instruments for speculative purposes. At the inception of a new derivative, we designate the derivative as a hedge or we determine the derivative to be undesignated as a hedging instrument as the facts dictate. We document the relationships between the hedging instruments and the hedged items, as well as our risk management objectives and strategy for undertaking various hedge transactions. We assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of the hedged item at both the inception of the hedge and on an ongoing basis.

We have a program that primarily utilizes foreign currency forward contracts to reduce the risks associated with the effects of certain foreign currency exposures. Under this program, our strategy is to have gains or losses on the foreign currency forward contracts mitigate the foreign currency transaction and translation gains or losses to the extent practical. These foreign currency exposures typically arise from changes in the value of assets and liabilities which are denominated in currencies other than the functional currency. Our foreign currency forward contracts generally settle in less than 180 days. We record all derivatives as of the end of our reporting period in our consolidated balance sheet at fair value. For those forward contracts designated as fair value hedging instruments or held as undesignated hedging instruments, we record changes in fair value in our consolidated statements of income along with the change in fair value of the hedged item. Changes in the fair value of forward contracts designated as cash flow hedging instruments are recognized in other comprehensive income until the hedged item is recognized in earnings. For derivatives designated as a cash flow hedge, the ineffective portion of that derivative's change in fair value is recognized in earnings. Recognized gains and losses on derivatives entered into to manage foreign currency exchange risk are included in MG&A expenses in the consolidated statements of income.

We had outstanding foreign currency forward contracts with notional amounts aggregating $486 million and $207 million to hedge exposure to currency fluctuations in various foreign currencies at December 31, 2013 and 2012, respectively. These contracts are either undesignated hedging instruments or designated and qualify as fair value hedging instruments. The fair value was determined using quoted market prices for contracts with similar terms and maturity dates and was not material at either December 31, 2013 or 2012. The effects of our derivative instruments in our consolidated statements of income were not material in each of the three years ended December 31, 2013.

New Accounting Standards Updates

In February 2013, the FASB issued ASU No. 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*. This ASU requires entities to present separately, among other items, the amount of the change that is due to reclassifications, and the amount that is due to current period other comprehensive income. We adopted the new presentation requirements in the notes to our financial statements in the first quarter of 2013. For additional information see Note 12. Accumulated Other Comprehensive Loss.

In July 2012, the FASB issued an update to ASC 350, *Intangibles - Goodwill and Other*. This ASU amends the guidance in ASC 350-30 on testing indefinite-lived intangible assets for impairment. The revised guidance permits an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired as a basis for determining whether it is necessary to perform the quantitative impairment test. The ASU is effective for impairment tests performed for fiscal years beginning after September 15, 2012. We adopted this ASU for our 2013 impairment testing and it did not have a material impact on our consolidated financial statements.

NOTE 2. 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 generally recognized on a straight-line basis over the vesting period of the equity grant net of forfeitures. The compensation cost is determined 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, if necessary, in subsequent periods to reflect actual forfeitures. There were no stock-based compensation costs capitalized as the amounts were not material.

Stock-based compensation costs are as follows for the years ended December 31:

	2013	2012	2011
Stock-based compensation cost	$ 115	$ 115	$ 108
Tax benefit	(24)	(20)	(22)
Stock-based compensation cost, net of tax	$ 91	$ 95	$ 86

For our stock options and restricted stock awards and units, we currently have 32.5 million authorized for issuance and as of December 31, 2013, approximately 2 million shares were available for future grants. Our policy is to issue new shares for exercises of stock options, when restricted stock awards are granted, at vesting of restricted stock units, and issuances under the employee stock purchase plan.

Stock Options

Our stock option plans provide for the issuance of stock options to directors, officers and other key employees at an exercise price equal to the fair market value of the stock at the date of grant. Although subject to the terms of the stock option agreement, substantially all of the stock options become exercisable in three equal annual installments, beginning a year from the date of grant, and generally expire ten years from the date of grant. The stock option plans provide for the acceleration of vesting upon the employee’s retirement; therefore, the service period is reduced for employees that are or will become retirement eligible during the vesting period, and accordingly, the recognition of compensation expense for these employees is accelerated.

The fair value of each stock option granted is estimated using the Black-Scholes option pricing model. The following table presents the weighted average assumptions used in the option pricing model for options granted. The expected life of the options represents the period of time the options are expected to be outstanding. The expected life is based on our historical exercise trends and post-vest termination data incorporated into a forward-looking stock price model. The expected volatility is based on our implied volatility, which is the volatility forecast that is implied by the prices of actively traded options to purchase our stock observed in the market. The risk-free interest rate is based on the observed U.S. Treasury yield curve in effect at the time the options were granted. The dividend yield is based on our history of dividend payouts.

	2013	2012	2011
Expected life (years)	5.2	5.4	5.0
Risk-free interest rate	1.3%	0.9%	1.8%
Volatility	36.0%	41.4%	40.8%
Dividend yield	1.3%	1.4%	0.9%
Weighted average fair value per share at grant date	$ 13.79	$ 14.51	$ 24.20

The following table presents the changes in stock options outstanding and related information (in thousands, except per option prices):

	Number of Options	Weighted Average Exercise Price Per Option
Outstanding at December 31, 2012	11,156	$ 51.79
Granted	2,635	46.46
Exercised	(722)	35.84
Forfeited	(159)	48.23
Expired	(704)	70.27
Outstanding at December 31, 2013	12,206	$ 50.57
Exercisable at December 31, 2013	7,895	$ 52.58

The weighted average remaining contractual term for options outstanding and options exercisable at December 31, 2013 was 5.9 years and 5.2 years, respectively.

The total intrinsic value of stock options (defined as the amount by which the market price of our common stock on the date of exercise exceeds the exercise price of the option) exercised in 2013, 2012 and 2011 was $11 million, $3 million and $74 million, respectively. The income tax benefit realized from stock options exercised was $2.0 million, $0.8 million and $20 million in 2013, 2012 and 2011, respectively.

The total fair value of options vested in 2013, 2012 and 2011 was $31 million, $28 million and $22 million, respectively. As of December 31, 2013, there was $20 million of total unrecognized compensation cost related to unvested stock options, which is expected to be recognized over a weighted average period of two years.

The total intrinsic value of stock options outstanding at December 31, 2013 was $108 million, of which $67 million relates to options vested and exercisable. The intrinsic value for stock options outstanding is calculated as the amount by which the quoted price of $55.26 of our common stock as of the end of 2013 exceeds the exercise price of the options.

Restricted Stock Awards and Units

In addition to stock options, our officers, directors and key employees may be granted restricted stock awards (“RSA”), which is an award of common stock with no exercise price, or restricted stock units (“RSU”), where each unit represents the right to receive, at the end of a stipulated period, one unrestricted share of stock with no exercise price. RSAs and RSUs are subject to cliff or graded vesting, generally ranging over a three to five year period. We determine the fair value of restricted stock awards and restricted stock units based on the market price of our common stock on the date of grant. The following table presents the combined changes of RSAs and RSUs and related information (in thousands, except per share/unit prices):

	Number of Awards and Units	Weighted Average Grant Date Fair Value Per Award/Unit
Unvested balance at December 31, 2012	2,411	$ 50.71
Granted	1,596	45.58
Vested	(1,129)	51.60
Forfeited	(226)	48.34
Unvested balance at December 31, 2013	2,652	$ 47.44

The weighted average grant date fair value per share for RSAs and RSUs granted in 2013, 2012 and 2011 was $45.58, $47.10 and $63.01, respectively. The total fair value of RSAs and RSUs vested in 2013, 2012 and 2011 was $58 million, $55 million and $52 million, respectively. As of December 31, 2013, there was $70 million of total unrecognized compensation cost related to unvested RSAs and RSUs, which is expected to be recognized over a weighted average period of two years.

Employee Stock Purchase Plan

The Employee Stock Purchase Plan ("ESPP") provides for eligible employees to purchase shares on an after-tax basis in an amount between 1% and 10% of their annual pay: (i) on June 30 of each year at a 15% discount of the fair market value of our common stock on January 1 or June 30, whichever is lower, and (ii) on December 31 of each year at a 15% discount of the fair market value of our common stock on July 1 or December 31, whichever is lower. An employee may not purchase more than $5,000 in either of the six-month measurement periods described above or $10,000 annually.

We currently have 30.5 million shares authorized for issuance, and at December 31, 2013, there were 7.8 million shares reserved for future issuance. Compensation cost for the years ended December 31, was calculated using the Black-Scholes option pricing model with the following assumptions:

	2013	2012	2011
Expected life (years)	0.5	0.5	0.5
Risk-free interest rate	0.1%	0.1%	0.1%
Volatility	30.3%	44.1%	36.6%
Dividend yield	1.4%	1.3%	1.0%
Fair value per share of the 15% cash discount	$ 6.45	$ 6.71	$ 9.62
Fair value per share of the look-back provision	3.58	5.46	6.50
Total weighted average fair value per share at grant date	$ 10.03	$ 12.17	$ 16.12

We calculated estimated volatility using historical daily prices based on the expected life of the stock purchase plan. The risk-free interest rate is based on the observed U.S. Treasury yield curve in effect at the time the ESPP shares were granted. The dividend yield is based on our history of dividend payouts.

NOTE 3. INCOME TAXES

The provision for income taxes is comprised of the following for the years ended December 31:

	2013	2012	2011
Current:			
U.S.	$ 159	$ 251	$ 609
Foreign	452	528	479
Total current	611	779	1,088
Deferred:			
U.S.	(54)	(57)	(315)
Foreign	55	(57)	(177)
Total deferred	1	(114)	(492)
Provision for income taxes	$ 612	$ 665	$ 596

The geographic sources of income before income taxes are as follows for the years ended December 31:

	2013	2012	2011
U.S.	$ 512	$ 700	$ 1,466
Foreign	1,203	1,282	873
Income before income taxes	$ 1,715	$ 1,982	$ 2,339

The provision for income taxes differs from the amount computed by applying the U.S. statutory income tax rate to income before income taxes for the reasons set forth below for the years ended December 31:

	2013	2012	2011
U.S. statutory income tax rate	35.0%	35.0%	35.0%
Effect of foreign operations	(8.7)	(2.0)	(0.5)
Change in valuation allowances related to foreign losses	8.9	0.9	2.2
Adjustments of prior years' tax positions	0.9	(2.9)	(2.2)
State income taxes - net of U.S. tax benefit	0.8	1.8	1.7
Impact of reorganization of certain foreign subsidiaries	(1.0)	—	(9.1)
Other - net	(0.2)	0.8	(1.6)
Total effective tax rate	35.7%	33.6%	25.5%

During the fourth quarter of 2013, we recognized a net tax benefit of $18 million as a result of the reorganization of certain of our foreign subsidiaries. This included a $360 million tax benefit resulting from the reversal of a deferred tax liability related to our decision to indefinitely reinvest the earnings of certain foreign subsidiaries which was made in conjunction with the reorganization that occurred during the fourth quarter of 2013. Due to the fact that these undistributed foreign earnings are no longer a source of future income against which the foreign tax credits will be utilized, we also recognized a tax charge of $342 million to record a valuation allowance against certain foreign tax credit carryforwards.

During 2011, we reorganized certain of our foreign subsidiaries. As a result of the reorganization, previously accrued U.S. deferred income taxes related to those subsidiaries were reduced by $214 million to account for certain foreign tax credits that existed prior to the acquisition of BJ Services and are now available to offset future U.S. taxes.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes, as well as operating loss and tax credit carryforwards. The tax effects of our temporary differences and carryforwards are as follows at December 31:

	2013	2012
Deferred tax assets:		
Receivables	$ 68	$ 76
Inventory	347	250
Employee benefits	98	125
Other accrued expenses	185	154
Operating loss carryforwards	403	245
Tax credit carryforwards	462	460
Other	70	70
Subtotal	1,633	1,380
Valuation allowances	(949)	(389)
Total	684	991
Deferred tax liabilities:		
Goodwill and other intangibles	356	385
Property	459	355
Undistributed earnings of foreign subsidiaries	14	374
Other	24	27
Total	853	1,141
Net deferred tax liability	$ (169)	$ (150)

We record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of the deferred tax assets depends on the ability to generate sufficient taxable income of the appropriate character in the future and in the appropriate taxing jurisdictions. At December 31, 2013, valuation allowances totaled $949 million consisting of $382 million for operating loss carryforwards, $459 million for foreign tax credit carryforwards, and $108 million for other deferred tax assets in various jurisdictions. The increase in the valuation allowances of $560 million in 2013 resulted from net tax charges of $342 million related to foreign tax credit carryforwards in the U.S., as described above, and $218 million primarily related to foreign losses. There are $21 million of operating loss carryforwards without a valuation allowance which expire in varying amounts over the next twenty years.

We have provided relevant U.S. and foreign taxes for the anticipated repatriation of certain earnings of our foreign subsidiaries. At December 31, 2013 and 2012, the deferred tax liability for undistributed earnings of foreign subsidiaries totaled $14 million and $374 million, respectively. The decrease was primarily due to our decision to indefinitely reinvest the earnings of certain foreign subsidiaries. We consider the undistributed earnings of our foreign subsidiaries above the amount for which taxes have already been provided to be indefinitely reinvested, as we have no current intention to repatriate these earnings. As such, deferred income taxes are not provided for temporary differences of approximately $5.9 billion at December 31, 2013, representing earnings of non-U.S. subsidiaries intended to be indefinitely reinvested. These additional foreign earnings could become subject to additional tax, if remitted, or deemed remitted, as a dividend. Computation of the potential deferred tax liability associated with these undistributed earnings and any other basis differences, is not practicable.

At December 31, 2013, we had approximately $117 million of foreign tax credits which may be carried forward indefinitely under applicable foreign law, and $342 million of foreign tax credits which expire in 2015 through 2024 under U.S. tax law. In addition, at December 31, 2013, we had approximately $3 million of state tax credits which expire in 2018.

At December 31, 2013, we had $282 million of tax liabilities for total gross unrecognized tax benefits related to uncertain tax positions, which includes liabilities for interest and penalties of $37 million and $17 million, respectively. If we were to prevail on all uncertain tax positions, the net effect would be a decrease to our income tax provision of approximately $244 million. The remaining approximately $38 million is offset by deferred tax assets that represent tax benefits that would be received in different taxing jurisdictions in the event that we did not prevail on all uncertain tax positions.

The following table presents the changes in our gross unrecognized tax benefits and associated interest and penalties included in the consolidated balance sheets.

	Gross Unrecognized Tax Benefits, Excluding Interest and Penalties	Interest and Penalties	Total Gross Unrecognized Tax Benefits
Balance at December 31, 2010	$ 324	$ 114	$ 438
(Decrease) increase in prior year tax positions	(5)	12	7
Increase in current year tax positions	8	11	19
Decrease related to settlements with taxing authorities	(3)	(1)	(4)
Decrease related to lapse of statute of limitations	(38)	(38)	(76)
Decrease due to effects of foreign currency translation	(3)	(2)	(5)
Balance at December 31, 2011	283	96	379
Decrease in prior year tax positions	(18)	(5)	(23)
Increase in current year tax positions	6	1	7
Decrease related to settlements with taxing authorities	(34)	(9)	(43)
Decrease related to lapse of statute of limitations	(38)	(9)	(47)
Decrease due to effects of foreign currency translation	(3)	(3)	(6)
Balance at December 31, 2012	196	71	267
Increase (decrease) in prior year tax positions	20	(2)	18
Increase in current year tax positions	44	1	45
Decrease related to settlements with taxing authorities	(15)	(4)	(19)
Decrease related to lapse of statute of limitations	(17)	(10)	(27)
Decrease due to effects of foreign currency translation	—	(2)	(2)
Balance at December 31, 2013	$ 228	$ 54	$ 282

It is expected that the amount of unrecognized tax benefits will change in the next twelve months due to expiring statutes, audit activity, tax payments, competent authority proceedings related to transfer pricing, or final decisions in matters that are the subject of litigation in various taxing jurisdictions in which we operate. At December 31, 2013, we had approximately $99 million of tax liabilities, net of $20 million of tax assets, related to uncertain tax positions, each of which are individually insignificant, and each of which are reasonably possible of being settled within the next twelve months.

At December 31, 2013, approximately $163 million of tax liabilities for total gross unrecognized tax benefits were included in the noncurrent portion of our income tax liabilities, for which the settlement period cannot be determined; however, it is not expected to be within the next twelve months.

We operate in more than 80 countries and are subject to income taxes in most taxing jurisdictions in which we operate. The following table summarizes the earliest tax years that remain subject to examination by the major taxing jurisdictions in which we operate. These jurisdictions are those we project to have the highest tax liability for 2014.

Jurisdiction	Earliest Open Tax Period	Jurisdiction	Earliest Open Tax Period
Canada	2005	Norway	1999
Germany	2008	Saudi Arabia	2003
Netherlands	2008	U.S.	2010

NOTE 4. EARNINGS PER SHARE

A reconciliation of the number of shares used for the basic and diluted earnings per share ("EPS") computations is as follows for the years ended December 31:

	2013	2012	2011
Weighted average common shares outstanding for basic EPS	443	440	436
Effect of dilutive securities - stock plans	1	1	2
Adjusted weighted average common shares outstanding for diluted EPS	444	441	438
Future potentially dilutive shares excluded from diluted EPS:			
Options with an exercise price greater than the average market price for the period	4	7	3

NOTE 5. INVENTORIES

Inventories, net of reserves of $382 million and $346 million in 2013 and 2012, respectively, are comprised of the following at December 31:

	2013	2012
Finished goods	$ 3,438	$ 3,336
Work in process	215	228
Raw materials	231	217
Total inventories	$ 3,884	$ 3,781

NOTE 6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are comprised of the following at December 31:

	Useful Life	2013	2012
Land		$ 294	$ 253
Buildings and improvements	5 - 30 years	2,621	2,408
Machinery, equipment and other	1 - 20 years	13,380	12,361
Subtotal		16,295	15,022
Less: Accumulated depreciation		7,219	6,315
Total property, plant and equipment		$ 9,076	$ 8,707

Depreciation expense relating to property, plant and equipment was $1,579 million, $1,427 million and $1,221 million in 2013, 2012 and 2011, respectively.

NOTE 7. GOODWILL AND INTANGIBLE ASSETS

The changes in the carrying amount of goodwill are detailed below by segment.

	North America	Latin America	Europe/ Africa/ Russia Caspian	Middle East/ Asia Pacific	Industrial Services	Total Goodwill
Balance at December 31, 2012	$ 3,069	$ 586	$ 1,018	$ 852	$ 433	$ 5,958
Acquisitions and other	(4)	1	12	—	(1)	8
Balance at December 31, 2013	$ 3,065	$ 587	$ 1,030	$ 852	$ 432	$ 5,966

We perform an annual impairment test of goodwill as of October 1 of every year. There were no impairments of goodwill in any of the three years ended December 31, 2013 related to the annual impairment test.

Intangible assets are comprised of the following at December 31:

	2013			2012		
	Gross Carrying Amount	Less: Accumulated Amortization	Net	Gross Carrying Amount	Less: Accumulated Amortization	Net
Technology	$ 814	$ 337	$ 477	$ 787	$ 282	$ 505
Customer relationships	494	157	337	494	117	377
Trade names	120	82	38	121	60	61
Other [(1)]	43	12	31	60	10	50
Total intangibles	$ 1,471	$ 588	$ 883	$ 1,462	$ 469	$ 993

(1) Includes indefinite-lived intangibles of $27 million and $44 million at December 31, 2013 and 2012, respectively, related to in-process research and development projects.

During 2011, we recognized impairments of certain trade names, the majority of which related to the impairment of the BJ Services trade name. As a result, we recorded a charge of $315 million before-tax ($220 million net of tax) in net income. The BJ Services trade name was classified as an indefinite lived intangible asset and, therefore, was not being amortized. The impairment of the BJ Services trade name was due to the decision to minimize the use of the BJ Services trade name as part of our overall branding strategy. The BJ Services trade name was revalued resulting in a revised fair value of $61 million, with a remaining useful life of 3 years, which we began amortizing in 2012 on an accelerated basis.

The following table details the impairment charge by segment:

	2011
North America	$ 105
Latin America	64
Europe/Africa/Russia Caspian	48
Middle East/Asia Pacific	47
Industrial Services	51
Total	$ 315

Intangible assets are generally amortized on a straight-line basis with estimated useful lives ranging from 3 to 30 years. Amortization expense included in net income for the years ended December 31, 2013, 2012 and 2011 was $119 million, $140 million and $96 million, respectively. Estimated amortization expense for each of the subsequent five fiscal years is expected to be as follows:

Year	Estimated Amortization Expense
2014	104
2015	97
2016	95
2017	92
2018	86

NOTE 8. INDEBTEDNESS

Total debt consisted of the following at December 31, net of unamortized discount and debt issuance cost:

	2013	2012
6.0% Notes due June 2018 with an effective interest rate of 4.8%	$ 260	$ 263
7.5% Senior Notes due November 2018 with an effective interest rate of 7.6%	745	744
3.2% Senior Notes due August 2021 with an effective interest rate of 3.3%	744	743
8.55% Debentures due June 2024 with an effective interest rate of 8.8%	148	148
6.875% Notes due January 2029 with an effective interest rate of 7.1%	394	393
5.125% Notes due September 2040 with an effective interest rate of 5.2%	1,480	1,480
Commercial paper with an effective interest rate of 0.2%	254	925
Other debt with an effective interest rate of 11.1%	356	220
Total debt	4,381	4,916
Less: short-term debt and current portion of long-term debt	499	1,079
Total long-term debt	$ 3,882	$ 3,837

The estimated fair value of total debt at December 31, 2013 and 2012 was $4,857 million and $5,829 million, respectively, which differs from the carrying amounts of $4,381 million and $4,916 million, respectively, included in our consolidated balance sheets. The fair value was determined using quoted period end market prices.

At December 31, 2013 we had a $2.5 billion committed revolving credit facility maturing in September 2016. As of December 31, 2013, we were in compliance with all of the facility's covenants. There were no direct borrowings under the committed revolving credit facility during 2013. We also have a commercial paper program under which we may issue up to $2.5 billion in commercial paper with maturities of no more than 270 days. The maximum combined borrowing at any point in time under both the commercial paper program and the credit facility is $2.5 billion. At December 31, 2013, we had $254 million of commercial paper outstanding. Maturities of debt at December 31, 2013 are as follows: 2014 - $499 million; 2015 - $21 million; 2016 - $17 million; 2017 - $11 million; 2018 - $1,018 million; and $2,815 million thereafter.

In 2011, we redeemed in full our 6.5% Senior Notes due in November 2013, which resulted in the payment of a redemption premium of $63 million and in a pre-tax loss on the early extinguishment of this debt of $40 million, which included the redemption premium and the write off of the remaining original debt issuance cost and debt discount, partially offset by a gain of $25 million from the termination of two related interest rate swap agreements.

NOTE 9. SEGMENT INFORMATION

We are a supplier of oilfield services, products, technology and systems to the worldwide oil and natural gas business, referred to as oilfield operations, which are managed through operating segments that are aligned with our geographic regions. We also provide services and products to the downstream chemicals, and process and pipeline industries, referred to as Industrial Services.

During the fourth quarter of 2013, we realigned our oilfield operations organizational and management structure and internal reporting process such that oilfield operations are now managed and organized through four geographic regions consisting of North America, Latin America, Europe/Africa/Russia Caspian, and Middle East/Asia Pacific. These four regions represent our operating and reportable segments for oilfield operations. Previously, they consisted of eight geographic regions which represented our operating segments that were aggregated into four reportable segments. However, the four reportable segments historically disclosed are the same under our new reporting structure; therefore, there is no change to our prior period disclosures as it relates to this realignment. In addition, our Industrial Services businesses are reported in a fifth operating segment.

REVENUE AND PROFIT BEFORE TAX

The performance of our operating segments is evaluated based on profit before tax, which is defined as income before income taxes and before the following: net interest expense, corporate expenses, and certain gains and losses not allocated to the operating segments.

Summarized financial information is shown in the following table:

	2013		2012		2011	
Segments	**Revenue**	**Profit (Loss) Before Tax**	**Revenue**	**Profit (Loss) Before Tax**	**Revenue**	**Profit (Loss) Before Tax**
North America	$ 10,878	$ 968	$ 10,836	$ 1,268	$ 10,279	$ 1,908
Latin America	2,307	66	2,399	197	2,190	223
Europe/Africa/Russia Caspian	3,850	570	3,634	586	3,372	336
Middle East/Asia Pacific	4,050	478	3,275	313	2,852	310
Industrial Services	1,279	135	1,217	131	1,138	95
Total Operations	22,364	2,217	21,361	2,495	19,831	2,872
Corporate and other	—	(268)	—	(303)	—	(272)
Interest expense, net	—	(234)	—	(210)	—	(221)
Loss on early extinguishment of debt	—	—	—	—	—	(40)
Total	$ 22,364	$ 1,715	$ 21,361	$ 1,982	$ 19,831	$ 2,339

During the first quarter of 2012, we changed our reporting structure to include the reservoir development services business ("RDS") within our four geographic segments. All prior period segment disclosures for revenue and profit before tax have been reclassified to include RDS within our four geographic segments. The impact of these changes to the Industrial Services segment was to reduce revenue by $108 million for the year ended December 31, 2011, and increase profit before tax by $42 million for the year ended December 31, 2011. For 2011, segment profit before tax includes the charge of $315 million related to the impairment of trade names. For further discussion of the trade name impairments and breakdown by segment, see Note 7. Goodwill and Intangible Assets.

ASSETS

During the fourth quarter of 2013, we revised our reporting related to certain shared assets carried at the enterprise level that support our global operations. As a result, we now report these separately as shared assets along with the related capital expenditures. Previously, these assets were reported within the Industrial Services segment or were allocated among the geographical regions within oilfield operations. Accordingly, all prior period segment disclosures related to assets and capital expenditures have been revised to reflect this change.

The following table presents total assets by segment at December 31:

	2013	2012	2011
Segments	**Assets**	**Assets**	**Assets**
North America	$ 9,672	$ 9,533	$ 9,168
Latin America	2,709	2,740	2,539
Europe/Africa/Russia Caspian	3,969	3,617	3,552
Middle East/Asia Pacific	3,834	3,537	3,173
Industrial Services	980	978	947
Shared assets	5,110	5,044	4,557
Total Operations	26,274	25,449	23,936
Corporate and other	1,660	1,240	911
Total	$ 27,934	$ 26,689	$ 24,847

Shared assets consist primarily of the assets carried at the enterprise level and include our supply chain, product line technology and information technology organizations. These assets are used to support our operating segments and consist primarily of manufacturing inventory, property, plant and equipment used in manufacturing and information technology, intangible assets related to technology and certain deferred tax assets. All costs and expenses from these organizations, including depreciation and amortization, are allocated to our operating segments as these enterprise organizations support our global operations. Corporate assets include cash, certain facilities, and certain other noncurrent assets. The impact of the changes to previously reported segment assets is shown in the following table:

	Assets Increase/(decrease)	
Segments	**2012**	**2011**
North America	$ (643)	$ (641)
Latin America	(158)	(191)
Europe/Africa/Russia Caspian	(279)	(296)
Middle East/Asia Pacific	(148)	(148)
Industrial Services	(3,814)	(3,280)
Shared assets	5,044	4,557
Total Operations	2	1
Corporate and other	(2)	(1)
Total	$ —	$ —

CAPITAL EXPENDITURES AND DEPRECIATION AND AMORTIZATION

The following table presents capital expenditures and depreciation and amortization by segment for the years ended December 31:

	2013		2012		2011	
Segments	Capital Expenditures	Depreciation and Amortization	Capital Expenditures	Depreciation and Amortization	Capital Expenditures	Depreciation and Amortization
North America	$ 718	$ 814	$ 1,333	$ 750	$ 1,212	$ 625
Latin America	198	235	222	225	265	202
Europe/Africa/Russia/Caspian	419	291	358	257	345	236
Middle East/Asia Pacific	375	279	332	234	218	207
Industrial Services	53	58	40	55	36	49
Shared assets	262	—	604	—	351	—
Total Operations	2,025	1,677	2,889	1,521	2,427	1,319
Corporate and other	60	21	21	47	34	2
Total	$ 2,085	$ 1,698	$ 2,910	$ 1,568	$ 2,461	$ 1,321

The impact of the changes to previously reported segment capital expenditures to reflect the change in reporting of shared assets is shown in the following table:

	Capital Expenditures Increase/(decrease)	
Segments	2012	2011
North America	$ (40)	$ (31)
Latin America	(12)	(9)
Europe/Africa/Russia Caspian	(16)	(12)
Middle East/Asia Pacific	(13)	(10)
Industrial Services	(523)	(289)
Shared assets	604	351
Total	$ —	$ —

OTHER

The following table presents geographic consolidated revenue based on where the product is shipped or the services are performed for the years ended December 31:

	2013	2012	2011
U.S.	$ 10,133	$ 9,903	$ 9,131
Canada and other	1,446	1,598	1,768
North America	11,579	11,501	10,899
Latin America (1)	2,368	2,436	2,220
Europe/Africa/Russia Caspian	4,162	3,981	3,671
Middle East/Asia Pacific	4,255	3,443	3,041
Total	$ 22,364	$ 21,361	$ 19,831

(1) Latin America includes Mexico, and Central and South America.

The following table presents consolidated revenue for each category of similar products and services for the years ended December 31:

	2013	2012	2011
Completion and Production	$ 13,323	$ 12,949	$ 12,469
Drilling and Evaluation	7,762	7,195	6,224
Industrial Services	1,279	1,217	1,138
Total	$ 22,364	$ 21,361	$ 19,831

The following table presents net property, plant and equipment by its geographic location at December 31:

	2013	2012	2011
U.S.	$ 4,582	$ 4,627	$ 3,752
Canada and other	571	642	529
North America	5,153	5,269	4,281
Latin America (1)	887	912	891
Europe/Africa/Russia Caspian	1,734	1,419	1,325
Middle East/Asia Pacific	1,302	1,107	918
Total	$ 9,076	$ 8,707	$ 7,415

(1) Latin America includes Mexico, and Central and South America.

NOTE 10. EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT PLANS

We have both funded and unfunded noncontributory defined benefit pension plans ("Pension Benefits") covering certain employees primarily in the U.S., the U.K., Germany and Canada. Under the provisions of the U.S. qualified pension plan (the "U.S. Plan"), a hypothetical cash balance account is established for each participant. Such accounts receive quarterly credits based on a percentage according to the employee's age on the last day of the quarter applied to quarterly eligible compensation and interest credits based on the balance in the account on the last day of the quarter. The plans are frozen for the majority of the participants in the U.K. and Canada pension plans; therefore, we do not accrue benefits for those participants. The Germany pension plan is an unfunded plan where benefits are based on creditable years of service, creditable pay and accrual rates. We also provide certain postretirement health care benefits ("other postretirement benefits"), through an unfunded plan, to a closed group of U.S. employees who retire and have met certain age and service requirements. This plan was amended during 2012 and as a result was closed to new participants as of December 31, 2012. This amendment resulted in a reduction in the benefit obligation of $69 million, which was recorded as a prior service credit in accumulated other comprehensive loss in 2012.

Funded Status

Below is the reconciliation of the beginning and ending balances of benefit obligations, fair value of plan assets and the funded status of our plans.

	U.S. Pension Benefits		Non-U.S. Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012	2013	2012
Change in benefit obligation:						
Benefit obligation at beginning of year	$ 589	$ 524	$ 740	$ 643	$ 148	$ 196
Service cost	65	63	12	8	6	13
Interest cost	21	21	31	32	5	7
Actuarial loss (gain)	2	20	36	76	(22)	16
Benefits paid	(24)	(34)	(24)	(22)	(9)	(15)
Plan amendments	—	—	—	9	—	(69)
Curtailment/settlements	—	—	(3)	(23)	—	—
Other	(4)	(5)	—	(8)	—	—
Foreign currency translation adjustments	—	—	7	25	—	—
Benefit obligation at end of year	649	589	799	740	128	148
Change in plan assets:						
Fair value of plan assets at beginning of year	524	433	592	526	—	—
Actual return on plan assets	78	53	52	43	—	—
Employer contributions	43	76	18	44	9	15
Benefits paid	(24)	(34)	(24)	(22)	(9)	(15)
Curtailment/settlements	—	—	(2)	(23)	—	—
Other	(4)	(4)	—	—	—	—
Foreign currency translation adjustments	—	—	9	24	—	—
Fair value of plan assets at end of year	617	524	645	592	—	—
Funded status - underfunded at end of year	$ (32)	$ (65)	$ (154)	$ (148)	$ (128)	$ (148)
Accumulated benefit obligation	$ 599	$ 540	$ 767	$ 700	$ 128	$ 148

The amounts recognized in the consolidated balance sheets consist of the following at December 31:

	U.S. Pension Benefits		Non-U.S. Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012	2013	2012
Noncurrent assets	$ —	$ —	$ 12	$ 2	$ —	$ —
Current liabilities	(2)	(2)	(7)	(8)	(14)	(15)
Noncurrent liabilities	(30)	(63)	(159)	(142)	(114)	(133)
Net amount recognized	$ (32)	$ (65)	$ (154)	$ (148)	$ (128)	$ (148)

The funded status position represents the difference between the benefit obligation and the plan assets. The projected benefit obligation ("PBO") for pension benefits represents the actuarial present value of benefits attributed to employee services and compensation and includes an assumption about future compensation levels. The accumulated benefit obligation ("ABO") is the actuarial present value of pension benefits attributed to employee service to date and present compensation levels. The ABO differs from the PBO in that the ABO does not include any assumptions about future compensation levels.

Information for the plans with ABOs in excess of plan assets is as follows at December 31:

	U.S. Pension Benefits		Non-U.S. Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012	2013	2012
Projected benefit obligation	$ 18	$ 19	$ 399	$ 395	n/a	n/a
Accumulated benefit obligation	$ 17	$ 19	$ 371	$ 366	$ 128	$ 148
Fair value of plan assets	$ —	$ —	$ 237	$ 255	n/a	n/a

Weighted average assumptions used to determine benefit obligations for these plans are as follows for the years ended December 31:

	U.S. Pension Benefits		Non-U.S. Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012	2013	2012
Discount rate	4.5%	3.6%	4.4%	4.4%	4.0%	3.2%
Rate of compensation increase	5.6%	5.6%	4.4%	4.4%	n/a	n/a
Social security increase	2.8%	2.8%	2.4%	2.1%	n/a	n/a

The development of the discount rate for our U.S. plans and substantially all non-U.S. plans was based on a bond matching model, whereby a hypothetical bond portfolio of high-quality, fixed-income securities is selected that will match the cash flows underlying the projected benefit obligation.

Accumulated Other Comprehensive Loss

The amount recorded before-tax in accumulated other comprehensive loss related to employee benefit plans consists of the following at December 31:

	U.S. Pension Benefits		Non-U.S. Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012	2013	2012
Net actuarial loss	$ 156	$ 205	$ 209	$ 193	$ 27	$ 53
Net prior service cost (credit)	1	2	3	9	(87)	(95)
Total	$ 157	$ 207	$ 212	$ 202	$ (60)	$ (42)

The estimated net actuarial loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and included in net periodic benefit cost in 2014 are $13 million and $1 million, respectively. The estimated net actuarial loss and prior service credit for the other postretirement benefits that will be amortized from accumulated other comprehensive loss and included in net periodic benefit cost in 2014 are $2 million and $7 million, respectively.

Net Periodic Cost

The components of net periodic cost are as follows for the years ended December 31:

	U.S. Pension Benefits			Non-U.S. Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Service cost	$ 65	$ 63	$ 38	$ 12	$ 8	$ 9	$ 6	$ 13	$ 8
Interest cost	21	21	21	31	32	33	5	7	8
Expected return on plan assets	(39)	(35)	(31)	(37)	(36)	(33)	—	—	—
Amortization of prior service credit	—	—	—	—	—	—	(7)	(2)	(2)
Amortization of net actuarial loss	13	15	10	8	6	4	2	1	—
Curtailment/settlements	—	—	—	2	4	(4)	—	—	—
Net periodic cost	$ 60	$ 64	$ 38	$ 16	$ 14	$ 9	$ 6	$ 19	$ 14

Weighted average assumptions used to determine net periodic cost for these plans are as follows for the years ended December 31:

	U.S. Pension Benefits			Non-U.S. Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Discount rate	3.6%	4.2%	4.9%	4.4%	5.0%	5.5%	3.2%	3.8%	4.9%
Expected long-term return on plan assets	7.4%	7.4%	7.8%	6.5%	6.7%	6.7%	n/a	n/a	n/a
Rate of compensation increase	5.6%	5.4%	5.4%	4.4%	4.4%	4.3%	n/a	n/a	n/a
Social security increase	2.8%	2.8%	2.8%	2.1%	2.1%	2.9%	n/a	n/a	n/a

In selecting the expected rate of return on plan assets, we consider the average rate of earnings expected on the funds invested or to be invested to provide for the benefits of these plans. This includes considering the trusts' asset allocation and the expected returns likely to be earned over the life of the plans.

Health Care Cost Trend Rates

Assumed health care cost trend rates have a significant effect on the amounts reported for other postretirement benefits. As of December 31, 2013, the health care cost trend rate was 7.7% for employees under age 65, declining gradually each successive year until it reaches 4.5%. A one percentage point change in assumed health care cost trend rates would have had the following effects on 2013:

	One Percentage Point Increase	One Percentage Point Decrease
Effect on total of service and interest cost components	$ 0.2	$ (0.2)
Effect on postretirement welfare benefit obligation	$ 4.1	$ (4.1)

Plan Assets

We have investment committees that meet regularly to review the portfolio returns and to determine asset-mix targets based on asset/liability studies. Third-party investment consultants assist such committees in developing asset allocation strategies to determine our expected rates of return and expected risk for various investment portfolios. The investment committees considered these strategies in the formal establishment of the current asset-mix targets based on the projected risk and return levels for all major asset classes.

The majority of investments are held in the form of units of funds. The funds hold underlying securities and are redeemable as of the measurement date. Investments in equities and fixed-income funds are generally measured at fair value based on daily closing prices provided by active exchanges or on the basis of observable, market-based inputs. Investments in hedge funds are generally measured at fair value on the basis of their net asset values, which are provided by the investment sponsor or third party administrator. The fair values of private equity investments and real estate funds are based on appraised values developed using comparable market transactions or discounted cash flows.

U.S. Qualified Pension Plan

The investment policy of the U.S. Plan was developed after examining the historical relationships of risk and return among asset classes and the relationship between the expected behavior of the U.S. Plan's assets and liabilities. The investment policy of the U.S. Plan is designed to provide the greatest probability of meeting or exceeding the U.S. Plan's objectives at the lowest possible risk. In evaluating risk, the investment committee for the U.S. Plan ("U.S. Committee") reviews the long-term characteristics of various asset classes, focusing on balancing risk with expected return. Accordingly, the U.S. Committee selected the following six asset classes as allowable investments for the assets of the U.S. Plan: U.S. equities, non-U.S. equities, global fixed-income securities, real estate, hedge funds and private equity.

The fair value of the assets in our U.S. Plan at December 31, 2013 and 2012, by asset category, are presented below and were determined based on valuation techniques categorized as follows:

- Level One: The use of quoted prices in active markets for identical financial instruments.
- Level Two: The use of quoted prices for similar instruments in active markets or quoted prices for identical or similar instruments in markets that are not active or other inputs that are observable in the market or can be corroborated by observable market data.
- Level Three: The use of significantly unobservable inputs that typically require the use of management's estimates of assumptions that market participants would use in pricing.

	2013				2012			
Asset Category	**Total Asset Value**	**Level One**	**Level Two**	**Level Three**	**Total Asset Value**	**Level One**	**Level Two**	**Level Three**
Cash and Cash Equivalents	$ 5	$ 4	$ 1	$ —	$ 3	$ —	$ 3	$ —
Fixed Income (1)	111	—	111	—	101	—	101	—
Non-U.S. Equity (2)	132	—	132	—	111	—	111	—
U.S. Equity (3)	148	—	148	—	106	—	106	—
Hedge Funds (4)	190	—	—	190	172	—	—	172
Real Estate Funds (5)	9	—	—	9	7	—	—	7
Real Estate Investment Trust Equity	6	—	6	—	8	—	8	—
Private Equity Fund (6)	16	—	—	16	16	—	—	16
Total	$ 617	$ 4	$ 398	$ 215	$ 524	$ —	$ 329	$ 195

(1) A multi-manager strategy investing in fixed income securities. The current allocation includes: 40% in corporate bonds; 20% in government agencies; 15% in government bonds; 15% in government mortgage-backed securities; 5% in municipal bonds; 3% in asset-backed securities; and 2% in cash and other securities.

(2) Multi-manager strategy investing in common stocks of non-U.S. listed companies using both value and growth approaches.

(3) Multi-manager strategy investing in common stocks of U.S. listed companies using value and growth approaches.

(4) Strategies taking long and short positions in equities, fixed income securities, currencies and derivative contracts.

(5) Strategy investing in the global private real estate secondary market using a value-based investment approach.

(6) Partnership making opportunistic investments on a global basis across asset classes, capital structures and geographies.

Non-U.S. Pension Plans

The investment policies of our pension plans with plan assets, which are primarily in Canada and the U.K., (the "Non-U.S. Plans"), cover the asset allocations that the governing boards believe are the most appropriate for these Non-U.S. Plans in the long-term, taking into account the nature of the liabilities they expect to incur. The suitability of asset allocations and investment policies are reviewed periodically to ensure alignment with plan liabilities.

The table below presents the fair value of the assets in our Non-U.S. Plans by asset category and by valuation technique at December 31:

	2013				2012			
Asset Category	**Total Asset Value**	**Level One**	**Level Two**	**Level Three**	**Total Asset Value**	**Level One**	**Level Two**	**Level Three**
Cash and Cash Equivalents	$ 1	$ 1	$ —	$ —	$ 14	$ 14	$ —	$ —
Asset Allocation (1)	125	—	125	—	136	—	136	—
Bonds - Canada - Government (2)	32	32	—	—	—	—	—	—
Bonds - U.K. - Corporate (3)	79	—	79	—	72	—	72	—
Bonds - U.K. - Government (4)	200	—	200	—	170	—	170	—
Equities (5)	169	—	169	—	164	—	164	—
Real Estate Fund (6)	21	—	—	21	20	—	—	20
Insurance contracts	18	—	—	18	16	—	—	16
Total	$ 645	$ 33	$ 573	$ 39	$ 592	$ 14	$ 542	$ 36

(1) Invests in mixes of global common stocks and bonds to achieve broad diversification.
(2) Invests in Canadian Dollar-denominated government issued bonds intended to match the duration of plan liabilities.
(3) Invests passively in British Pound Sterling-denominated investment grade corporate bonds.
(4) Invests passively in British Pound Sterling-denominated government issued bonds.
(5) Invests in broad equity funds based on securities offered in various regions or countries. Equity funds are allocated by region as follows: 57% Global; 15% U.K.; 9% Emerging Markets; 7% North America; 6% Asia Pacific; and 6% Europe.
(6) Invests in a diversified range of property throughout the U.K., principally in the retail, office and industrial/ warehouse sectors.

The following table presents the changes in the fair value of assets determined using level 3 unobservable inputs:

	U.S. Private Equity Fund	**U.S. Real Estate Fund**	**U.S. Hedge Funds**	**Non-U.S. Real Estate Fund**	**Non-U.S. Insurance Contracts**	**Total**
Balance at December 31, 2010	$ —	$ 14	$ —	$ 19	$ 16	$ 49
Unrealized gains	—	2	—	—	—	2
Sales	—	(15)	—	—	(2)	(17)
Purchases	—	4	110	—	1	115
Balance at December 31, 2011	—	5	110	19	15	149
Unrealized (losses) gains	(2)	—	10	1	4	13
Sales	—	—	—	—	(5)	(5)
Purchases	18	2	52	—	2	74
Balance at December 31, 2012	16	7	172	20	16	231
Unrealized gains	2	—	12	1	2	17
Realized gains	—	—	7	—	—	7
Sales	(10)	—	(84)	—	(2)	(96)
Purchases	8	2	83	—	2	95
Balance at December 31, 2013	$ 16	$ 9	$ 190	$ 21	$ 18	$ 254

Expected Cash Flows

For all pension plans, we make annual contributions to the plans in amounts equal to or greater than amounts necessary to meet minimum governmental funding requirements. In 2014, we expect to contribute between $30 million and $34 million to our U.S. pension plans and between $72 million and $80 million to the non-U.S. pension plans. In 2014, we also expect to make benefit payments related to other postretirement benefits of between $13 million and $15 million.

The following table presents the expected benefit payments over the next ten years. The U.S. and non-U.S. pension benefit payments are made by the respective pension trust funds.

Year	U.S. Pension Benefits	Non-U.S. Pension Benefits	Other Postretirement Benefits
2014	$ 36	$ 20	$ 14
2015	$ 40	$ 20	$ 14
2016	$ 43	$ 23	$ 13
2017	$ 48	$ 28	$ 13
2018	$ 51	$ 30	$ 13
2019-2023	$ 308	$ 190	$ 61

DEFINED CONTRIBUTION PLANS

During the periods reported, generally all of our U.S. employees were eligible to participate in our sponsored 401(k) plan (“Thrift Plan”). The Thrift Plan allows eligible employees to elect to contribute portions of their salaries to an investment trust. Employee contributions are matched by the Company in cash at the rate of $1.00 per $1.00 employee contribution for the first 5% of the employee’s salary, and such contributions vest immediately. In addition, we make cash contributions for all eligible employees between 2% and 5% of their salary depending on the employee’s age. Such contributions are fully vested to the employee after three years of employment. The Thrift Plan provides several investment options, for which the employee has sole investment discretion. The Thrift Plan does not offer the Company's common stock as an investment option. Our contributions to the Thrift Plan and several other non-U.S. defined contribution plans amounted to $240 million, $232 million and $189 million in 2013, 2012 and 2011, respectively.

For certain non-U.S. employees who are not eligible to participate in the Thrift Plan, we provide a non-qualified defined contribution international retirement plan that provides basically the same benefits as those provided in the Thrift Plan. In addition, we provide a non-qualified supplemental retirement plan (“SRP”) for certain officers and employees whose benefits under the Thrift Plans and/or the U.S. qualified pension plan are limited by federal tax law. The SRP also allows eligible employees to defer a portion of their eligible compensation and provides for employer matching and base contributions pursuant to limitations. Both non-qualified plans are invested through trusts, and the assets and corresponding liabilities are included in our consolidated balance sheets. Our contributions to these non-qualified plans amounted to $15 million, $17 million and $11 million in 2013, 2012 and 2011, respectively. In 2014, we estimate we will contribute between $270 million and $293 million to all of our defined contribution plans.

POSTEMPLOYMENT BENEFITS

We provide certain postemployment disability income, medical and other benefits to substantially all qualifying former or inactive U.S. employees. Income benefits for long-term disability are provided through a fully-insured plan. The continuation of medical and other benefits while on disability (“Continuation Benefits”) are provided through a qualified self-insured plan. The accrued postemployment liability for Continuation Benefits at December 31, 2013 and 2012 was $23 million and $26 million, respectively, and is included in other liabilities in our consolidated balance sheets.

NOTE 11. COMMITMENTS AND CONTINGENCIES

LEASES

At December 31, 2013, we had long-term non-cancelable operating leases covering certain facilities and equipment. The minimum annual rental commitments, net of amounts due under subleases, for each of the five years in the period ending December 31, 2018 are $405 million, $258 million, $150 million, $84 million and $30 million, respectively, and $122 million in the aggregate thereafter. Rent expense was $702 million, $559 million and $401 million for the years ended December 31, 2013, 2012 and 2011, respectively. We have not entered into any significant capital leases during the three years ended December 31, 2013.

LITIGATION

We are subject to a number of lawsuits and claims arising out of the conduct of our business. The ability to predict the ultimate outcome of such matters involves judgments, estimates and inherent uncertainties. We record a liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated, including accruals for self-insured losses which are calculated based on historical claim data, specific loss development factors and other information. A range of total possible losses for all litigation matters cannot be reasonably estimated. Based on a consideration of all relevant facts and circumstances, we do not expect the ultimate outcome of any currently pending lawsuits or claims against us will have a material adverse effect on our financial position, results of operations or cash flows; however, there can be no assurance as to the ultimate outcome of these matters.

We insure against risks arising from our business to the extent deemed prudent by our management and to the extent insurance is available, but no assurance can be given that the nature and amount of that insurance will be sufficient to fully indemnify us against liabilities arising out of pending or future legal proceedings or other claims. Most of our insurance policies contain deductibles or self-insured retentions in amounts we deem prudent and for which we are responsible for payment. In determining the amount of self-insurance, it is our policy to self-insure those losses that are predictable, measurable and recurring in nature, such as claims for automobile liability, general liability and workers compensation.

On October 21, 2013, a collective action lawsuit alleging that we failed to pay an as-yet-undetermined class of workers overtime in compliance with the Fair Labor Standards Act was filed titled *Zamora et al. v. Baker Hughes Incorporated, Civil Action No. 2:13-CV-00326*, in the U.S. District Court for the Southern District of Texas, Corpus Christi Division. On October 10, 2013, a class and collective action lawsuit alleging that we failed to pay a nationwide class of workers overtime in compliance with the Fair Labor Standards Act and certain state laws was filed titled *Lea et al. v. Baker Hughes, Inc., Civil Action No. 3:13-CV-00447*, in the U.S. District Court for the Southern District of Texas, Galveston Division. We are evaluating the background facts and at this time cannot provide an evaluation of the likelihood of an unfavorable outcome or potential settlement terms.

On May 30, 2013, we received a Civil Investigative Demand ("CID") from the United States Department of Justice ("DOJ") pursuant to the Antitrust Civil Process Act. The CID seeks documents and information from us for the period from May 29, 2011 through the date of the CID in connection with a DOJ investigation related to pressure pumping services in the United States. We are working with the DOJ to provide the requested documents and information. We are not able to predict what action, if any, might be taken in the future by the DOJ or other governmental authorities as a result of the investigation.

On September 19, 2012, our subsidiary, Baker Hughes Oilfield Operations, Inc. (“BHOO”) terminated a sand supply agreement it had entered into with Hi-Crush Operating, LLC (“Hi-Crush”) on October 28, 2011 (as amended by the First Amendment to Supply Agreement on May 10, 2012, collectively the “Supply Agreement”) as a result of Hi-Crush's breach of the Supply Agreement. On November 12, 2012, Hi-Crush filed a lawsuit against BHOO in the 129th Judicial District Court in Harris County, Texas., *Cause No. 2012-67261; Hi-Crush Operating, LLC v. Baker Hughes Oilfield Operations, Inc.* In its petition, Hi-Crush claimed that BHOO's termination was “invalid” constituting a breach and that BHOO “anticipatorily repudiated the Supply Agreement without just excuse.” Hi-Crush claimed that it was entitled to recover liquidated damages of $187 million based on the undelivered Minimum Purchase

Requirement provision defined in the Supply Agreement; in the alternative, Hi-Crush sought an unspecified amount of actual damages. On December 17, 2012, BHOO filed a responsive pleading denying Hi-Crush's allegations and also filed a counter claim for breach of contract. On October 10, 2013, BHOO and Hi-Crush entered into a settlement agreement pursuant to which both parties agreed to jointly dismiss the above litigation. In connection with this settlement agreement, the parties have entered into a new supply agreement. The settlement agreement did not have a material impact on our financial position, results of operations or cash flows.

We were among several unrelated companies who received a subpoena from the Office of the New York Attorney General, dated June 17, 2011. The subpoena received by the Company seeks information and documents relating to, among other things, natural gas development and hydraulic fracturing. We are discussing the subpoena with the New York Attorney General's office.

ENVIRONMENTAL MATTERS

Our past and present operations include activities which are subject to extensive domestic (including U.S. federal, state and local) and international environmental regulations with regard to air, land and water quality and other environmental matters. Our environmental procedures, policies and practices are designed to ensure compliance with existing laws and regulations and to minimize the possibility of significant environmental damage.

We are involved in voluntary remediation projects at some of our present and former manufacturing locations or other facilities, the majority of which relate to properties no longer actively used in operations. On rare occasions, remediation activities are conducted as specified by a government agency-issued consent decree or agreed order. Remediation costs are accrued based on estimates of probable exposure using currently available facts, existing environmental permits, technology and presently enacted laws and regulations. Remediation cost estimates include direct costs related to the environmental investigation, external consulting activities, governmental oversight fees, treatment equipment and costs associated with long-term operation, maintenance and monitoring of a remediation project.

We have also been identified as a potentially responsible party (“PRP”) in remedial activities related to various Superfund sites. In these instances, we participate in the process set out in the Joint Participation and Defense Agreement to negotiate with government agencies, identify other PRPs, and determine each PRP’s allocation and estimate remediation costs. We have accrued what we believe to be our pro-rata share of the total estimated cost of remediation and associated management of these Superfund sites. This share is based upon the ratio that the estimated volume of waste we contributed to the site bears to the total estimated volume of waste disposed at the site. Applicable U.S. federal law imposes joint and several liability on each PRP for the cleanup of these sites leaving us with the uncertainty that we may be responsible for the remediation cost attributable to other PRPs who are unable to pay their share. No accrual has been made under the joint and several liability concept for those Superfund sites where our participation is de minimis since we believe that the probability that we will have to pay material costs above our volumetric share is remote. We believe there are other PRPs who have greater involvement on a volumetric calculation basis, who have substantial assets and who may be reasonably expected to pay their share of the cost of remediation. For those Superfund sites where we are a significant PRP, remediation costs are estimated to include recalcitrant parties. In some cases, we have insurance coverage or contractual indemnities from third parties to cover a portion of the ultimate liability.

Our total accrual for environmental remediation is $34 million and $32 million, which includes accruals of $4 million and $4 million for the various Superfund sites, at December 31, 2013 and 2012, respectively. The determination of the required accruals for remediation costs is subject to uncertainty, including the evolving nature of environmental regulations and the difficulty in estimating the extent and type of remediation activity that is necessary.

OTHER

In the normal course of business with customers, vendors and others, we have entered into off-balance sheet arrangements, such as surety bonds for performance, letters of credit and other bank issued guarantees, which totaled approximately $1.5 billion at December 31, 2013. It is not practicable to estimate the fair value of these financial instruments. None of the off-balance sheet arrangements either has, or is likely to have, a material effect on our consolidated financial statements. We also had commitments outstanding for purchase obligations related to capital expenditures, inventory and services under contracts, for each of the five years in the period ending December 31, 2018 of $483 million, $419 million, $259 million, $222 million and $121 million, respectively, and $168 million in the aggregate thereafter.

NOTE 12. ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table presents the changes in accumulated other comprehensive loss, net of tax:

	Pensions and Other Postretirement Benefits	Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Loss
Balance at December 31, 2011	$ (251)	$ (304)	$ (555)
Other comprehensive income before reclassifications:			
Foreign currency translation adjustments		78	78
Pensions and other postretirement benefits:			
Actuarial net loss arising in the year	(66)		(66)
Plan amendments	60		60
Foreign currency translation adjustments	(4)		(4)
Deferred taxes	(6)		(6)
Amounts reclassified from accumulated other comprehensive loss:			
Amortization of net actuarial loss	22		22
Amortization of prior service credit	(2)		(2)
Curtailment/settlements	4		4
Deferred taxes	(7)		(7)
Balance at December 31, 2012	(250)	(226)	(476)
Other comprehensive income before reclassifications:			
Foreign currency translation adjustments		(61)	(61)
Pensions and other postretirement benefits:			
Actuarial net gain arising in the year	38		38
Deferred taxes	(17)		(17)
Amounts reclassified from accumulated other comprehensive loss:			
Amortization of net actuarial loss	23		23
Amortization of prior service credit	(7)		(7)
Curtailment/settlements	2		2
Deferred taxes	(6)		(6)
Balance at December 31, 2013	$ (217)	$ (287)	$ (504)

The amounts reclassified from accumulated other comprehensive loss during the twelve months ended December 31, 2013 and 2012 represent the amortization of net actuarial loss, prior service credit and curtailments and settlements which are included in the computation of net periodic pension cost (see Note 10. Employee Benefit Plans for additional details). Net periodic pension cost is recorded in cost of sales and services, research and engineering, and marketing, general and administrative expenses.

NOTE 13. QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total Year
2013					
Revenue	$ 5,230	$ 5,487	$ 5,787	$ 5,860	$ 22,364
Gross Profit [(1)]	777	765	895	818	3,255
Net income attributable to Baker Hughes	267	240	341	248	1,096
Basic earnings per share attributable to Baker Hughes	0.60	0.54	0.77	0.56	2.47
Diluted earnings per share attributable to Baker Hughes	0.60	0.54	0.77	0.56	2.47
Dividends per share	0.15	0.15	0.15	0.15	0.60
Common stock market prices:					
High	47.96	48.22	50.38	58.66	
Low	42.01	43.21	46.22	48.64	
2012					
Revenue	$ 5,355	$ 5,326	$ 5,355	$ 5,325	$ 21,361
Gross Profit [(1)]	966	944	841	757	3,508
Net income attributable to Baker Hughes	379	439	279	214	1,311
Basic earnings per share attributable to Baker Hughes	0.86	1.00	0.63	0.49	2.98
Diluted earnings per share attributable to Baker Hughes	0.86	1.00	0.63	0.49	2.97
Dividends per share	0.15	0.15	0.15	0.15	0.60
Common stock market prices:					
High	52.40	44.76	50.10	47.10	
Low	40.79	38.13	38.85	39.64	

[(1)] Represents revenue less cost of sales, cost of services and research and engineering.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this annual report, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act of 1934, as amended (the "Exchange Act"). This evaluation was carried out under the supervision and with the participation of our management, including our principal executive officer and principal financial officer. Based on this evaluation, these officers have concluded that, as of December 31, 2013, our disclosure controls and procedures, as defined by Rule 13a-15(e) of the Exchange Act, are effective at a reasonable assurance level.

Disclosure controls and procedures are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act, such as this annual report, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Design and Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management included a report of their assessment of the design and effectiveness of our internal controls over financial reporting as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2013. Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting. Management's report and the independent registered public accounting firm's attestation report are included in Item 8 under the caption entitled "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" and are incorporated herein by reference.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal controls over financial reporting during the quarter ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding the Business Code of Conduct and Code of Ethical Conduct Certificates for our principal executive officer, principal financial officer and principal accounting officer are described in Item 1. Business of this Annual Report. Information concerning our directors is set forth in the sections entitled “Proposal No. 1, Election of Directors,” and “Corporate Governance - Committees of the Board” in our Definitive Proxy Statement for the 2014 Annual Meeting of Stockholders to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year on December 31, 2013 (“Proxy Statement”), which sections are incorporated herein by reference. For information regarding our executive officers, see “Item 1. Business - Executive Officers” in this Annual Report on Form 10-K. Additional information regarding compliance by directors and executive officers with Section 16(a) of the Exchange Act is set forth under the section entitled “Compliance with Section 16(a) of the Securities Exchange Act of 1934” in our Proxy Statement, which section is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

Information for this item is set forth in the following sections of our Proxy Statement, which sections are incorporated herein by reference: “Compensation Discussion and Analysis,” “Director Compensation,” “Compensation Committee Interlocks and Insider Participation” and “Compensation Committee Report.”

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information concerning security ownership of certain beneficial owners and our management is set forth in the sections entitled “Voting Securities” and “Security Ownership of Management” in our Proxy Statement, which sections are incorporated herein by reference.

Our Board of Directors has approved procedures for use under our Securities Trading and Disclosure Policy to permit our employees, officers and directors to enter into written trading plans complying with Rule 10b5-1 under the Exchange Act. Rule 10b5-1 provides criteria under which such an individual may establish a prearranged plan to buy or sell a specified number of shares of a company’s stock over a set period of time. Any such plan must be entered into in good faith at a time when the individual is not in possession of material, nonpublic information. If an individual establishes a plan satisfying the requirements of Rule 10b5-1, such individual’s subsequent receipt of material, nonpublic information will not prevent transactions under the plan from being executed. Certain of our officers have advised us that they have and may enter into a stock sales plan for the sale of shares of our common stock which are intended to comply with the requirements of Rule 10b5-1 of the Exchange Act. In addition, the Company has and may in the future enter into repurchases of our common stock under a plan that complies with Rule 10b5-1 or Rule 10b-18 of the Exchange Act.

Equity Compensation Plan Information

The information in the following table is presented as of December 31, 2013 with respect to shares of our common stock that may be issued under our existing equity compensation plans, including the Baker Hughes Incorporated 2002 Employee Long-Term Incentive Plan, the Baker Hughes Incorporated 2002 Director & Officer Long-Term Incentive Plan, the BJ Services 2000 Incentive Plan, the BJ Services 2003 Incentive Plan, the Employee Stock Purchase Plan, all of which have been approved by our stockholders (in millions, except per share prices).

Equity Compensation Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (excluding securities reflected in the first column)
Stockholder-approved plans (excluding Employee Stock Purchase Plan)	12.1	$ 50.57	1.5
Nonstockholder-approved plans (1)	0.1	46.72	0.5
Subtotal (except for weighted average exercise price)	12.2	50.57	2.0
Employee Stock Purchase Plan (2)	—	—	7.8
Total	12.2	$ 50.57	9.8

(1) The table includes the following nonstockholder-approved plan: the Director Compensation Deferral Plan. A description of this plan is set forth below.

(2) The per share purchase price under the Baker Hughes Incorporated Employee Stock Purchase Plan is determined in accordance with section 423 of the Code and is 85% of the lower of the fair market value of a share of our common stock on the date of grant or the date of purchase.

Our nonstockholder-approved plan is described below:

Director Compensation Deferral Plan

The Baker Hughes Incorporated Director Compensation Deferral Plan, as amended and restated effective January 1, 2009 and as further amended on July 25, 2013 (the “Deferral Plan”), is intended to provide a means for members of our Board of Directors to defer compensation otherwise payable and provide flexibility with respect to our compensation policies. Under the provisions of the Deferral Plan, directors may elect to defer income with respect to each calendar year. The compensation deferrals may be stock option-related deferrals or cash-based deferrals. If a director elects a stock option-related deferral, on the last day of each calendar quarter he or she will be granted a non-qualified stock option. The number of shares subject to the stock option is calculated by multiplying the amount of the deferred compensation that otherwise would have been paid to the director during the quarter by 4.4 and then dividing by the fair market value of our common stock on the last day of the quarter. The per share exercise price of the option will be the fair market value of a share of our common stock on the date the option is granted. Stock options granted under the Deferral Plan vest on the first anniversary of the date of grant and must be exercised within ten years of the date of grant. If a director’s directorship terminates for any reason, any options outstanding will expire on the earlier of five years after the termination of the directorship or the option expiration date. The maximum aggregate number of shares of our common stock that may be issued under the Deferral Plan is 0.5 million. As of December 31, 2013, options covering approximately 17,000 shares of our common stock were outstanding under the Deferral Plan, there were approximately 3,000 shares exercised during fiscal year 2013 and approximately 0.5 million shares remained available for future options.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information for this item is set forth in the sections entitled “Corporate Governance-Director Independence” and “Certain Relationships and Related Transactions” in our Proxy Statement, which sections are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information concerning principal accountant fees and services is set forth in the section entitled “Fees Paid to Deloitte & Touche LLP” in our Proxy Statement, which section is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) List of Documents filed as part of this Report.

(1) Financial Statements

All financial statements of the Registrant as set forth under Item 8 of this Annual Report on Form 10-K.

(2) Financial Statement Schedules

Schedule II—Valuation and Qualifying Accounts

(3) Exhibits

Each exhibit identified below is filed as a part of this report. Exhibits designated with an "*" are filed as an exhibit to this Annual Report on Form 10-K. Exhibits designated with a "+" are identified as management contracts or compensatory plans or arrangements. Exhibits previously filed as indicated below are incorporated by reference.

3.1	Certificate of Amendment dated April 22, 2010 and the Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended March 31, 2010).
3.2	Restated Bylaws of Baker Hughes Incorporated effective as of October 24, 2013 (filed as Exhibit 3.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed October 25, 2013).
4.1	Rights of Holders of the Company's Long-Term Debt. The Company has no long-term debt instrument with regard to which the securities authorized there under equal or exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis. The Company agrees to furnish a copy of its long-term debt instruments to the SEC upon request.
4.2	Certificate of Amendment dated April 22, 2010 and the Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended March 31, 2010).
4.3	Restated Bylaws of Baker Hughes Incorporated effective as of October 24, 2013 (filed as Exhibit 3.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed October 25, 2013).
4.4	Indenture dated as of May 15, 1994 between Western Atlas Inc. and The Bank of New York, Trustee, providing for the issuance of securities in series (filed as Exhibit 4.4 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2004).
4.5	Indenture dated October 28, 2008, between Baker Hughes Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (filed as Exhibit 4.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed October 29, 2008).
4.6	First Supplemental Indenture, dated August 17, 2011, between Baker Hughes Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (including form of Notes) (filed as Exhibit 4.2 to the Current Report of Baker Hughes Incorporated on Form 8-K filed August 23, 2011).
4.7	Officers' Certificate of Baker Hughes Incorporated dated October 28, 2008 establishing the 6.50% Senior Notes due 2013 and the 7.50% Senior Notes due 2018 (filed as Exhibit 4.2 to the Current Report of Baker Hughes Incorporated on Form 8-K filed October 29, 2008).
4.8	Form of 7.50% Senior Notes Due 2018 (filed as Exhibit 4.4 to the Current Report of Baker Hughes Incorporated on Form 8-K filed October 29, 2008).
4.9	Officers' Certificate of Baker Hughes Incorporated dated August 24, 2010 establishing the 5.125% Senior Notes due 2040 (filed as Exhibit 4.2 to the Current Report of Baker Hughes Incorporated on Form 8-K filed August 24, 2010).
4.10	Form of 5.125% Senior Notes due 2040 (filed as Exhibit 4.3 to the Current Report of Baker Hughes Incorporated on Form 8-K filed August 24, 2010).

4.11 Indenture, dated June 8, 2006, between BJ Services Company, as issuer, and Wells Fargo Bank, N.A., as trustee (filed as Exhibit 4.1 to the Current Report of BJ Services Company on Form 8-K filed on June 12, 2006).

4.12 Third Supplemental Indenture, dated May 19, 2008, between BJ Services Company, as issuer, and Wells Fargo Bank, N.A., as trustee, with respect to the 6% Senior Notes due 2018 (filed as Exhibit 4.2 to the Current Report of BJ Services Company on Form 8-K filed on May 23, 2008).

4.13 Fourth Supplemental Indenture, dated April 28, 2010, between BJ Services Company, as issuer, BSA Acquisition LLC, Baker Hughes Incorporated and Wells Fargo Bank, N.A., as trustee, with respect to the 5.75% Senior Notes due 2011 and the 6% Senior Notes due 2018 (filed as Exhibit 4.4 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on April 29, 2010).

4.14 Fifth Supplemental Indenture, dated June 21, 2011, between BJ Services Company LLC, as company, Western Atlas Inc. as successor company and Wells Fargo Bank, N.A., as trustee, with respect to the 6.00% Senior Notes due 2018 (incorporated by reference to Exhibit 4.4 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on June 23, 2011).

4.15+ Form of Incentive Stock Option Assumption Agreement for BJ Services incentive plans (filed as Exhibit 4.5 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on April 29, 2010).

4.16+ Form of Nonqualified Stock Option Assumption Agreement for BJ Services incentive plans (filed as Exhibit 4.6 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on April 29, 2010).

4.17 Registration Rights Agreement dated August 17, 2011 among Baker Hughes Incorporated and J.P. Morgan Securities LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of the several initial purchasers named therein (filed as Exhibit 10.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on August 23, 2011).

10.1+ Form of Amended and Restated Change in Control Agreement between Baker Hughes Incorporated and each of the executive officers effective as of January 1, 2009 (filed as Exhibit 10.2 to the Current Report of Baker Hughes Incorporated on Form 8-K filed December 19, 2008).

10.2+ Form of Change in Control Agreement between Baker Hughes Incorporated and certain of the executive officers effective as of July 16, 2012 (filed as Exhibit 10.1 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended June 30, 2012).

10.3+ Form of Executive Loyalty, Confidentiality, Non-Solicitation, and Non-Competition Agreement between Baker Hughes Incorporated and certain of the executive officers (filed as Exhibit 10.3 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2011).

10.4+* Letter Agreement between Baker Hughes Incorporated and Peter A. Ragauss dated December 8, 2013.

10.5+ Amendment and Restatement of the Baker Hughes Incorporated Change in Control Severance Plan effective as of January 1, 2009 (filed as Exhibit 10.3 to the Current Report of Baker Hughes Incorporated on Form 8-K filed December 19, 2008).

10.6+ Form of Indemnification Agreement between Baker Hughes Incorporated and each of the directors and executive officers (filed as Exhibit 10.4 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2003).

10.7+ Form of Amendment to the Indemnification Agreement between Baker Hughes Incorporated and each of the directors and executive officers effective as of January 1, 2009 (filed as Exhibit 10.4 to the Current Report of Baker Hughes Incorporated on Form 8-K filed December 19, 2008).

10.8+ Baker Hughes Incorporated Director Retirement Policy for Certain Members of the Board of Directors (filed as Exhibit 10.10 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2003).

10.9+ Baker Hughes Incorporated Director Compensation Deferral Plan, as amended and restated effective as of January 1, 2009 (filed as Exhibit 10.2 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended June 30, 2008).

10.10+ Amendment to Baker Hughes Incorporated Director Compensation Deferral Plan effective as of January 1, 2009 (filed as Exhibit 10.5 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on December 19, 2008).

10.11+* Amendment to the Baker Hughes Incorporated Director Compensation Deferral Plan effective as of July 25, 2013.

10.12+ Baker Hughes Incorporated Executive Severance Plan, as amended and restated on February 7, 2008 (filed as Exhibit 10.17 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2007).

10.13+ Amendment to Exhibit A of Baker Hughes Incorporated Executive Severance Plan as of July 20, 2009 (filed as Exhibit 10.1 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended June 30, 2009).

10.14+ Amendment to Baker Hughes Incorporated Executive Severance Plan dated April 22, 2010 (filed as Exhibit 10.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on April 23, 2010).

10.15+ Baker Hughes Incorporated Annual Incentive Compensation Plan for officers, as amended and restated on January 23, 2014 (filed as Exhibit 10.5 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.16+ Baker Hughes Incorporated Supplemental Retirement Plan, as amended and restated effective as of January 1, 2012 (filed as Exhibit 10.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on December 20, 2011).

10.17+ Baker Hughes Incorporated 2002 Employee Long-Term Incentive Plan (filed as Exhibit 4.4 to the Registration Statement No. 333-87372 of Baker Hughes Incorporated on Form S-8 filed May 1, 2002).

10.18+ Amendment to Baker Hughes Incorporated 2002 Employee Long-Term Incentive Plan, effective July 24, 2008 (filed as Exhibit 10.4 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended June 30, 2008).

10.19+ Amendment to Baker Hughes Incorporated 2002 Employee Long-Term Incentive Plan dated March 31, 2010 (filed as Annex H to the Registration Statement No. 333-162463 of Baker Hughes Incorporated on Form S-4 filed on February 9, 2010).

10.20+ Baker Hughes Incorporated 2002 Director & Officer Long-Term Incentive Plan (filed as Exhibit 10.2 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended September 30, 2003).

10.21+ Amendment to 2002 Director & Officer Long-Term Incentive Plan, effective as of October 27, 2005 (filed as Exhibit 10.3 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended September 30, 2005).

10.22+ Amendment to Baker Hughes Incorporated 2002 Director & Officer Long-Term Incentive Plan effective July 24, 2008 (filed as Exhibit 10.3 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended June 30, 2008).

10.23+ Amendment to Baker Hughes Incorporated 2002 Director & Officer Long-Term Incentive Plan dated March 31, 2010 (filed as Annex G to the Registration Statement No. 333-162463 of Baker Hughes Incorporated on Form S-4 filed on February 9, 2010).

10.24+ Baker Hughes Incorporated Employee Stock Purchase Plan, as amended and restated, effective as of January 1, 2012 (filed as Exhibit 10.25 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ending December 31, 2012).

10.25+ Amendment to the Baker Hughes Incorporated Employee Stock Purchase Plan effective as of April 25, 2013 (filed as Exhibit 10.2 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on April 30, 2013).

10.26+ Form of Baker Hughes Incorporated Incentive Stock Option Agreement with Terms and Conditions for officers (filed as Exhibit 10.33 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2009).

10.27+ Form of Baker Hughes Incorporated Nonqualified Stock Option Agreement with Terms and Conditions for officers (filed as Exhibit 10.30 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2009).

10.28+ Form of Baker Hughes Incorporated Nonqualified Stock Option Award Agreement and Terms and Conditions for officers (filed as Exhibit 10.70 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2011).

10.29+ Form of Baker Hughes Incorporated Nonqualified Stock Option Award Agreement and Terms and Conditions for officers (filed as Exhibit 10.6 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.30+ Form of Baker Hughes Incorporated Incentive Stock Option Award Agreement and Terms and Conditions for officers (filed as Exhibit 10.71 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2011).

10.31+ Form of Baker Hughes Incorporated Incentive Stock Option Award Agreement and Terms and Conditions for officers (filed as Exhibit 10.7 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.32+ Form of Baker Hughes Incorporated Restricted Stock Award with Terms and Conditions for officers (filed as Exhibit 10.37 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2009).

10.33+ Form of Baker Hughes Incorporated Restricted Stock Unit Award Agreement and Terms and Conditions for officers (filed as Exhibit 10.41 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2009).

10.34+ Form of Baker Hughes Incorporated Restricted Stock Award, including Terms and Conditions for directors (filed as Exhibit 10.40 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2005).

10.35+ Form of Baker Hughes Incorporated Restricted Stock Unit Award Agreement and Terms and Conditions for officers (filed as Exhibit 10.9 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.36+ Form of Baker Hughes Incorporated Restricted Stock Award Agreement and Terms and Conditions for officers (filed as Exhibit 10.8 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.37+ Form of Baker Hughes Incorporated Restricted Stock Unit Award, including Terms and Conditions for directors (filed as Exhibit 10.34 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ending December 31, 2012).

10.38+ Form of Baker Hughes Incorporated Stock Option Award Agreement, including Terms and Conditions for directors (filed as Exhibit 10.41 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2005).

10.39+ Form of Baker Hughes Incorporated Performance Unit Award Agreement and Terms and Conditions for officers (filed as Exhibit 10.72 to the Annual Report of Baker Hughes Incorporated on Form 10-K for the year ended December 31, 2011).

10.40+ Form of Baker Hughes Incorporated Performance Unit Award Agreement and Terms and Conditions for certain officers payable in cash (filed as Exhibit 10.3 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.41+ Form of Baker Hughes Incorporated Performance Unit Award Agreement and Terms and Conditions for certain officers payable in shares (filed as Exhibit 10.4 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.42+ Performance Goals adopted January 25, 2012 for the Performance Unit Awards granted in 2012 under the Baker Hughes Incorporated 2002 Director & Officer Long-Term Incentive Plan (filed as Exhibit 10.39 to the Annual Report of Baker Hughes Incorporated on Form 10-K filed on February 13, 2013).

10.43+ Performance Goals adopted February 27, 2013 for the Performance Unit Awards granted in 2013 under the Baker Hughes Incorporated 2002 Director & Officer Long-Term Incentive Plan and 2002 Employee Long-Term Incentive Plan (filed as Exhibit 10.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on March 4, 2013).

10.44+ Performance Goals adopted January 22, 2014 for the Performance Unit Awards payable in cash granted in 2014 (filed as Exhibit 10.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.45+ Performance Goals adopted January 22, 2014 for the Performance Unit Awards payable in shares granted in 2014 (filed as Exhibit 10.2 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.46+ BJ Services Company 2000 Incentive Plan (filed as Appendix B to the Proxy Statement of BJ Services Company dated December 20, 2000).

10.47+ First Amendment effective March 22, 2001 to BJ Services Company 2000 Incentive Plan (filed as Exhibit 10.2 to the Registration Statement of BJ Services Company on Form S-8 (Reg. No. 333-73348).

10.48+ Second Amendment effective May 10, 2001 to BJ Services Company 2000 Incentive Plan (filed as Appendix D to the Proxy Statement of BJ Services Company dated April 10, 2001).

10.49+ Third Amendment effective October 15, 2001 to BJ Services Company 2000 Incentive Plan (filed as Exhibit 10.24 to the Annual Report of BJ Services Company on Form 10-K for the year ended September 30, 2001).

10.50+ Fifth Amendment effective November 15, 2006 to BJ Services Company 2000 Incentive Plan (filed as Exhibit 10.4 to the Current Report of BJ Services Company on Form 8-K filed on December 13, 2006).

10.51+ Sixth Amendment effective October 13, 2008 to BJ Services Company 2000 Incentive Plan (filed as Exhibit 10.22 to the Annual Report of BJ Services Company on Form 10-K for the year ended September 30, 2008).

10.52+ Seventh Amendment effective December 5, 2008 to BJ Services Company 2000 Incentive Plan (filed as Exhibit 10.3 to the Quarterly Report of BJ Services Company on Form 10Q for the quarter ended December 31, 2008).

10.53+ Amended and Restated BJ Services Company 2003 Incentive Plan (filed as Appendix A to the Proxy Statement of BJ Services Company dated December 15, 2008).

10.54+ First Amendment to the Amended and Restated BJ Services Company 2003 Incentive Plan (filed as Exhibit 10.1 to the Quarterly Report of BJ Services Company for the quarter ended March 31, 2009).

10.55+ Baker Hughes Incorporated Compensation Recoupment Policy effective January 1, 2014 (filed as Exhibit 10.10 to the Current Report of Baker Hughes Incorporated on Form 8-K filed on January 28, 2014).

10.56 Credit Agreement dated as of September 13, 2011, among Baker Hughes Incorporated, JP Morgan Chase Bank, N.A., as Administrative Agent and twenty-one lenders for $2.5 billion, in the aggregate for all banks (filed as Exhibit 10.1 to the Current Report of Baker Hughes Incorporated on Form 8-K filed September 14, 2011).

10.57 Plea Agreement between Baker Hughes Services International, Inc. and the United States Department of Justice filed on April 26, 2007, with the United States District Court of Texas, Houston Division (filed as Exhibit 10.5 to the Quarterly Report of Baker Hughes Incorporated on Form 10-Q for the quarter ended March 31, 2007).

21.1* Subsidiaries of Registrant.

23.1* Consent of Deloitte & Touche LLP.

31.1* Certification of Martin S. Craighead, Chairman and Chief Executive Officer, furnished pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.

31.2* Certification of Peter A. Ragauss, Chief Financial Officer, furnished pursuant to Rule 13a-14(a) of the Securities Exchange Act of 1934, as amended.

32* Statement of Martin S. Craighead, Chairman and Chief Executive Officer, and Peter A. Ragauss, Chief Financial Officer, furnished pursuant to Rule 13a-14(b) of the Securities Exchange Act of 1934, as amended.

95* Mine Safety Disclosures.

101.INS* XBRL Instance Document

101.SCH* XBRL Schema Document

101.CAL* XBRL Calculation Linkbase Document

101.LAB* XBRL Label Linkbase Document

101.PRE* XBRL Presentation Linkbase Document

101.DEF* XBRL Definition Linkbase Document

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BAKER HUGHES INCORPORATED

Date: February 12, 2014

/s/ MARTIN S. CRAIGHEAD
Martin S. Craighead
Chairman and Chief Executive Officer

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Martin S. Craighead and Peter A. Ragauss, each of whom may act without joinder of the other, as their true and lawful attorneys-in-fact and agents, each with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 12th day of February 2014.

Signature	Title
/s/ MARTIN S. CRAIGHEAD (Martin S. Craighead)	Chairman and Chief Executive Officer (principal executive officer)
/s/ PETER A. RAGAUSS (Peter A. Ragauss)	Senior Vice President and Chief Financial Officer (principal financial officer)
/s/ ALAN J. KEIFER (Alan J. Keifer)	Vice President and Controller (principal accounting officer)

Signature	Title
/S/ LARRY D. BRADY (Larry D. Brady)	Director
/S/ CLARENCE P. CAZALOT, JR. (Clarence P. Cazalot, Jr.)	Director
/S/ LYNN L. ELSENHANS (Lynn L. Elsenhans)	Director
/S/ ANTHONY G. FERNANDES (Anthony G. Fernandes)	Director
/S/ CLAIRE W. GARGALLI (Claire W. Gargalli)	Director
/S/ PIERRE H. JUNGELS (Pierre H. Jungels)	Director
/S/ JAMES A. LASH (James A. Lash)	Director
/S/ J. LARRY NICHOLS (J. Larry Nichols)	Director
/S/ JAMES W. STEWART (James W. Stewart)	Director
/S/ CHARLES L. WATSON (Charles L. Watson)	Director

Baker Hughes Incorporated
Schedule II - Valuation and Qualifying Accounts

(In millions)	Balance at Beginning of Period	Charged to Cost and Expenses	Write-offs [1]	Other Changes [2] [3]	Balance at End of Period
Year Ended December 31, 2013					
Reserve for doubtful accounts receivable	$ 308	$ 75	$ (115)	$ (30)	$ 238
Reserve for inventories	346	85	(46)	(3)	382
Year Ended December 31, 2012					
Reserve for doubtful accounts receivable	229	100	(22)	1	308
Reserve for inventories	304	68	(28)	2	346
Year Ended December 31, 2011					
Reserve for doubtful accounts receivable	162	84	(18)	1	229
Reserve for inventories	322	16	(36)	2	304

(1) Represents the elimination of accounts receivable and inventory deemed uncollectible or worthless.
(2) Represents transfers, currency translation adjustments and divestitures.
(3) For the year ended December 31, 2013, the reserve for doubtful accounts receivable includes a $30 million reduction due to the currency devaluation in Venezuela.

Corporate Information

Board of Directors

Larry D. Brady
Former Chairman and Chief Executive Officer, Intermec, Inc.

Clarence P. Cazalot, Jr.
Former Executive Chairman, President and Chief Executive Officer, Marathon Oil Corporation

Martin S. Craighead
Chairman and Chief Executive Officer, Baker Hughes Incorporated

Lynn L. Elsenhans
Former Executive Chairman, Chief Executive Officer and President, Sunoco, Inc.

Anthony G. Fernandes
Former Chairman, President and Chief Executive Officer, Philip Services Corporation

Claire W. Gargalli
Former Vice Chairman, Diversified Search and Diversified Health Search Companies

Pierre H. Jungels, CBE
Former President of the Institute of Petroleum

James A. Lash
Chairman, Manchester Principal LLC

J. Larry Nichols
Executive Chairman, Devon Energy Corporation

James W. Stewart
Former Chairman, President and Chief Executive Officer, BJ Services Company

Charles L. Watson
Chairman, Twin Eagle Management Resources

Executive Leadership

Martin S. Craighead
Chairman and Chief Executive Officer

Maria Borras
President, Latin America

Belgacem Chariag
President, Global Products and Services

Didier Charreton
Vice President, Human Resources

Alan R. Crain
Senior Vice President, Chief Legal and Governance Officer

Archana Deskus
Vice President and Chief Information Officer

Dmitry Kuzovenkov
Vice President, Health, Safety and Environment

Derek Mathieson
Vice President, Strategy and Corporate Development

Khaled Nouh
President, Middle East and Asia Pacific

Peter A. Ragauss
Senior Vice President and Chief Financial Officer

Mario Ruscev
Vice President and Chief Technology Officer

Arthur L. Soucy
President, Europe, Africa, Russia Caspian

Richard L. Williams
President, North America

Other Corporate Officers

Trey Clark
Vice President, Investor Relations

David E. Emerson
Vice President, Corporate Development

Mike W. Sumruld
Vice President and Treasurer

Alan J. Keifer
Vice President and Controller

William D. Marsh
Vice President and General Counsel

Jay G. Martin
Vice President, Chief Compliance Officer, and Senior Deputy General Counsel

Ronald E. Martz
Vice President, Internal Audit

Alex Peng
Vice President, Tax

Lee Whitley
Corporate Secretary and Senior Corporate Counsel

Stockholder Information
Transfer Agent and Registrar
Computershare Investor Services
P.O. Box 30170
College Station, Texas 77842-3170
(888) 216-8057

Stock Exchange Listings
Ticker Symbol "BHI"
New York Stock Exchange, Inc.
SIX Swiss Exchange

New York Stock Exchange
Last year our Annual CEO Certification, without qualifications, was timely submitted to the NYSE. Also, we file our certifications required under SOX as exhibits to our Form 10-K.

Investor Relations Office
Trey Clark
Vice President, Investor Relations
Baker Hughes Incorporated
P.O. Box 4740
Houston, Texas 77210-4740
ir@bakerhughes.com

Form 10-K
Additional copies of the Company's Annual Report to the Securities and Exchange Commission (Form 10-K) are available by writing:
Baker Hughes Investor Relations
P.O. Box 4740
Houston, Texas 77210-4740
Also available at our website:
http://www.bakerhughes.com/annualreport

Annual Meeting
The Company's Annual Meeting of Stockholders will be held:
9:00 a.m. Central Daylight Time
April 24, 2014
Plaza Banquet Room
2777 Allen Parkway
Houston, Texas 77019-2118

Corporate Office Location and Mailing Address
2929 Allen Parkway, Suite 2100
Houston, Texas 77019-2118
Telephone: (713) 439-8600
P.O. Box 4740
Houston, Texas 77210-4740

Website
www.bakerhughes.com

As a Baker Hughes stockholder, you are invited to take advantage of our convenient stockholder services or request more information about Baker Hughes. Computershare Investor Services our transfer agent, maintains the records for our registered stockholders and can help you with a variety of stockholder-related services at no charge, including:

- Change of name or address enrollment
- Duplicate mailings
- Lost stock certificates
- Additional administrative services
- Consolidation of accounts
- Transfer of stock to another person
- Dividend reinvestment

Access your investor statements online 24 hours a day, seven days a week.
For more information, go to https://www.computershare.com/investor

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