UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d)
of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) August 14, 2014

NATIONAL OILWELL VARCO, INC.
(Exact name of registrant as specified in its charter)

Delaware	1-12317	76-0475815
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

7909 Parkwood Circle Dr. Houston, Texas	77036
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 713-346-7500

(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events

On May 30, 2014, National Oilwell Varco, Inc. (“NOV” or the “Company”) completed the previously announced spin-off of its distribution business into an independent public company named NOW Inc. In conjunction with the spin-off of NOW Inc. the Company reviewed its reporting and management structure, and effective April 1, 2014, reorganized its Rig Technology, Petroleum Services & Supplies and remaining operations of Distribution & Transmission reporting segments into four new reporting segments. The new reporting segments are Rig Systems, Rig Aftermarket, Wellbore Technologies and Completion & Production Solutions.

In exhibit 99.1 to this Current Report on Form 8-K, NOV has revised the applicable sections within the following information as included in the 2013 Form 10-K to reflect the spin-off of NOW Inc. as discontinued operations as well as recast information to reflect the new reporting segments: Business; Risk Factors; Properties; Selected Financial Data; Management’s Discussion and Analysis of Financial Condition and Results of Operations; and Financial Statements and Supplementary Data. Except for information related to the spin-off and the new reporting segments, NOV has not made any revisions to its 2013 Form 10-K to update for other developments that have occurred since NOV filed its 2013 Form 10-K on February 14, 2014. This Current Report on Form 8-K should be read in conjunction with NOV’s 2013 Form 10-K, First Quarter 2014 Form 10-Q, Second Quarter 2014 Form 10-Q and other filings with the SEC. These filings contain important information regarding developments affecting NOV.

Item 9.01 Financial Statements and Exhibits

(d) *Exhibits*

The following exhibit is provided as part of the information furnished under Items 2.02 and 9.01 of this Current Report on Form 8-K:

23.1	Consent of Ernst & Young LLP.
99.1	Business; Risk Factors; Properties; Selected Financial Data; Management’s Discussion and Analysis of Financial Condition and Results of Operations; and Financial Statements and Supplementary Data, revised to reflect the spin-off of NOW Inc. as discontinued operations as well as recast information to reflect the new reporting segments.
101	The following materials from our Current Report on Form 8-K, filed August 14, 2014, formatted in eXtensible Business Reporting Language (XBRL): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Income, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Comprehensive Income, and (v) Notes to the Consolidated Financial Statements, tagged as block text.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Date: August 14, 2014

NATIONAL OILWELL VARCO, INC.

/s/ *Jeremy D. Thigpen*

Jeremy D. Thigpen
Senior Vice President and Chief Financial Officer
(Duly Authorized Officer, Principal Financial and Accounting Officer)

Index to Exhibits

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements of National Oilwell Varco, Inc. and in each related Prospectus of our reports dated February 14, 2014, except for Notes 1, 15, and 17, as to which the date is August 14, 2014, with respect to the consolidated financial statements and schedule of National Oilwell Varco, Inc., and February 14, 2014, with respect to the effectiveness of internal control over financial reporting of National Oilwell Varco, Inc., included in the Current Report (Form 8-K) of National Oilwell Varco, Inc. dated August 14, 2014, filed with the Securities and Exchange Commission.

Form	Description
S-8	National-Oilwell, Inc. Stock Award and Long Term Incentive Plan, Value Appreciation and Incentive Plan A and Value Appreciation and Incentive Plan B (No. 333-15859)
S-8	National-Oilwell Retirement and Thrift Plan (No. 333-36359)
S-8	National Oilwell Varco, Inc. Long-Term Incentive Plan (No. 333-123310)
S-8	National Oilwell Varco, Inc. Employee Stock Purchase Plan (No. 333-123301)
S-8	Varco International Inc. 2003 Equity Participation Plan; Stock Option Plan for Non-Employee Directors, as amended; Varco International, Inc. 1990 Stock Option Plan; 1994 Directors’ Stock Option Plan; Varco International, Inc. 401(k)/Profit Sharing Plan (No. 333-123287)
S-8	Varco International, Inc. Deferred Compensation Plan (No. 333-123286)
S-8	National-Oilwell, Inc. Amended and Restated Stock Award and Long-Term Incentive Stock Plan (No. 333-118721)
S-4	Registration Statement on Form S-4 for the registration of shares of common stock in conjunction with the merger with Varco International, Inc. (No. 333-119071)
S-8	National Oilwell Varco, Inc. Long-Term Incentive Plan (No. 333-159333)
S-3	Registration Statement on Form S-3 for the registration of debt securities (No. 333-184953)
S-8	National Oilwell Varco, Inc. Long-Term Incentive Plan (No. 333-188818)

/s/ Ernst & Young LLP

Houston, Texas

August 14, 2014

Exhibit 99.1

PART I

ITEM 1. BUSINESS

General

National Oilwell Varco, Inc. ("NOV" or the "Company"), a Delaware corporation incorporated in 1995, is a leading worldwide provider in the design, manufacture and sale of equipment and components used in oil and gas drilling, completion and production operations, and the provision of oilfield services to the upstream oil and gas industry. The Company conducts operations in over 880 locations across six continents.

The Company's principal executive offices are located at 7909 Parkwood Circle Drive, Houston, Texas 77036, its telephone number is (713) 346-7500, and its Internet website address is http://www.nov.com. The Company's annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and all amendments thereto, are available free of charge on its Internet website. These reports are posted on its website as soon as reasonably practicable after such reports are electronically filed with the Securities and Exchange Commission ("SEC"). The Company's Code of Ethics is also posted on its website.

The Company has a long tradition of pioneering innovations which improve the cost-effectiveness, efficiency, safety and environmental impact of oil and gas operations. The Company's common stock is traded on the New York Stock Exchange under the symbol "NOV". The Company operates through four reporting segments: Rig Systems, Rig Aftermarket, Wellbore Technologies and Completion & Production Solutions.

On May 30, 2014, the Company completed the previously announced spin-off ("spin-off") of its distribution business into an independent public company named NOW Inc., which trades on the New York Stock Exchange under the symbol "DNOW". After the close of the New York Stock Exchange on May 30, 2014, the stockholders of record as of May 22, 2014 (the "Record Date") received one share of NOW Inc. common stock for every four shares of NOV common shares as of the Record Date. No fractional shares of NOW Inc. common stock were distributed. Instead, the transfer agent aggregated any fractional shares into whole shares, sold those whole shares in the open market at prevailing rates and distributed the net cash proceeds, after deducting any taxes required to be withheld and any amount equal to all brokerage charges and commissions, pro rata to each holder who would otherwise have been entitled to receive fractional shares in the distribution.

Rig Systems

The Company's Rig Systems segment makes and supports the capital equipment and integrated systems needed to drill oil and gas wells on land and offshore. The segment designs, manufactures, and sells land rigs, offshore drilling equipment packages, including installation and commissioning services, and drilling rig components that mechanize and automate the rig process and functionality.

Equipment and technologies in Rig Systems include: substructures, derricks, and masts; cranes; pipe lifting, racking, rotating, and assembly systems; fluid transfer technologies, such as mud pumps; pressure control equipment, including blowout preventers; power transmission systems, including drives and generators; and rig instrumentation and control systems.

The Rig Systems segment primarily supports land and offshore drillers. Demand for Rig Systems products primarily depends on drilling contractors' and oil and gas companies' capital spending plans, specifically capital expenditures on rig construction and refurbishment.

Rig Aftermarket

The Company's Rig Aftermarket segment provides comprehensive aftermarket products and services to support land rigs and offshore rigs, and drilling rig components manufactured by the Rig Systems segment.

The segment provides spare parts, repair, and rentals as well as technical support, field service and first well support, field engineering, and customer training through a network of aftermarket service and repair facilities strategically located in major areas of drilling operations.

The Rig Aftermarket segment primarily supports land and offshore drillers. Demand for Rig Aftermarket products and services primarily depends on overall levels of oilfield drilling activity, which drives demand for spare parts, service, and repair for Rig System's large installed base of equipment; and secondarily on drilling contractors' and oil and gas companies' capital spending plans, specifically capital expenditures on rig refurbishment and re-certification.

Wellbore Technologies

The Company's Wellbore Technologies segment designs, manufactures, rents, and sells a variety of equipment and technologies used to perform drilling operations, and offers services that optimize their performance, including: solids control and waste management equipment and services, drilling fluids, premium drill pipe, wired pipe, tubular inspection and coating services, instrumentation, downhole tools, and drill bits.

The Wellbore Technologies segment focuses on oil and gas companies and supports drilling contractors, oilfield service companies, and oilfield rental companies. Demand for Wellbore Technologies products and services primarily depends on the level of oilfield drilling activity by oil and gas companies, drilling contractors, and oilfield service companies.

Completion & Production Solutions

The Company's Completion & Production Solutions segment integrates technologies for well completions and oil and gas production. The segment designs, manufactures, and sells equipment and technologies needed for hydraulic fracture stimulation, including pressure pumping trucks and pumps, blenders, sanders, hydration units, injection units, flowline, manifolds and wellheads; well intervention, including coiled tubing units, coiled tubing, and wireline units and tools; onshore production, including composite pipe, surface transfer and progressive cavity pumps, and artificial lift systems; and offshore production, including floating production systems and subsea production technologies.

The Completion & Production Solutions segment primarily supports service companies and oil and gas companies. Demand for Completion & Production Solutions products depends on the level of oilfield completions and workover activity by oilfield service companies and drilling contractors and capital spending plans by oil and gas companies and oilfield service companies.

The following table sets forth the contribution to our total revenues of our four reporting segments (in millions):

	Years Ended December 31,		
	2013	2012	2011
Revenue:			
Rig Systems	$ 8,552	$ 7,077	$ 5,686
Rig Aftermarket	2,692	2,138	1,876
Wellbore Technologies	5,109	5,184	4,455
Completion & Production Solutions	4,309	3,994	2,483
Eliminations	(1,441)	(1,199)	(1,025)
Total Revenue	$19,221	$17,194	$13,475

Sales from one segment to another generally are priced at estimated equivalent commercial selling prices; however, segments originating an external sale are credited with the full profit to the company. Eliminations include intercompany transactions conducted between the four reporting segments that are eliminated in consolidation. Intercompany transactions within each reporting segment are eliminated within each reporting segment.

See Note 15 to our Consolidated Financial Statements for financial information by segment and a geographical breakout of revenues and long-lived assets. We have included a glossary of oilfield terms at the end of Item 1. "Business" of this Current Report.

Influence of Oil and Gas Activity Levels on the Company's Business

The oil and gas industry in which the Company participates has historically experienced significant volatility. Demand for the Company's services and products depends primarily upon the general level of activity in the oil and gas industry worldwide, including the number of drilling rigs in operation, the number of oil and gas wells being drilled, the depth and drilling conditions of these wells, the volume of production, the number of well completions and the level of well remediation activity. Oil and gas activity is in turn heavily influenced by, among other factors, oil and gas prices worldwide. High levels of drilling and well remediation activity generally spurs demand for the Company's products and services used to drill and remediate oil and gas wells. Additionally, high levels of oil and gas activity increase cash flows available for oil and gas companies, drilling contractors, oilfield service companies, and manufacturers of oil country tubular goods ("OCTG") to invest in capital equipment that the Company sells.

Beginning in early 2004, increasing oil and gas prices led to steadily rising levels of drilling activity throughout the world. Concerns about the long-term availability of oil and gas supply also began to build. Consequently, the worldwide rig count increased 11% in 2006, 2% in 2007, and 7% in 2008. As a result of higher cash flows realized by many of the Company's customers, as well as the long-term concerns about supply-demand imbalance and the need to replace aging equipment, market conditions for capital equipment purchases improved significantly between 2006 and 2007, resulting in higher backlogs for the Company at the end of 2008 compared to the end of 2006 and 2007. However, as a result of the financial crisis and significantly lower commodity prices, the worldwide drilling rig count declined 31% in 2009 and customers were far less willing to commit to major capital equipment purchases in 2009. As a result, our order rates were substantially lower in 2009. In 2010, as the financial crisis eased and oil prices recovered, order rates began to improve across a broad array of rig equipment, with a particular focus on continued build out of the deepwater fleet. Each year 2011, 2012 and 2013 saw a further improvement in order rates as commodity prices remained at levels supporting sustained capital spending by our customers. However, the global rig count decreased 3% in 2013 compared to 2012 after rising by 1.5% in 2012 compared to 2011. Backlog for the Rig Systems segment at December 31, 2013, 2012 and 2011, was $15.0 billion, $10.9 billion and $9.2 billion, respectively. Backlog for the Completion & Production Solutions segment at December 31, 2013, 2012 and 2011 was $1.6 billion, $1.3 billion and $1.3 billion, respectively.

The willingness of oil and gas operators to make capital investments to explore for and produce oil and natural gas will continue to be influenced by numerous factors over which the Company has no control, including but not limited to: the ability of the members of the Organization of Petroleum Exporting Countries ("OPEC") to maintain oil price stability through voluntary production limits of oil; the level of oil production by non-OPEC countries; supply and demand for oil and natural gas; general economic and political conditions; costs of exploration and production; the availability of new leases and concessions; access to external financing; and governmental regulations regarding, among other things, environmental protection, climate change, taxation, price controls and product allocations. The willingness of drilling contractors and well servicing companies to make capital expenditures for the type of specialized equipment the Company provides is also influenced by numerous factors over which the Company has no control, including: the general level of oil and gas well drilling and servicing; rig day-rates; access to external financing; outlook for future increases in well drilling and well remediation activity; steel prices and fabrication costs; and government regulations regarding, among other things, environmental protection, taxation, and price controls.

See additional discussion on current worldwide economic environment and related oil and gas activity levels in Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Overview of Oil and Gas Well Construction Processes

Oil and gas wells are usually drilled by drilling contractors using a drilling rig. A bit is attached to the end of a drill stem, which is assembled by the drilling rig and its crew from 30-foot joints of drill pipe and specialized drilling components known as downhole tools. Using the conventional rotary drilling method, the drill stem is turned from the rotary table of the drilling rig by torque applied to the kelly, which is screwed into the top of the drill stem. Increasingly, drilling is performed using a drilling motor, which is attached to the bottom of the drill stem and provides rotational force directly to the bit, and a top drive, a device suspended from the derrick that turns the entire drill stem, rather than such force being supplied by the rotary table. The use of drilling motors and top drives permits the drilling contractor to drill directionally, including horizontally. The Company sells and rents drilling motors, drill bits, downhole tools and drill pipe through its Wellbore Technologies segment and sells top drives through its Rig Systems segment.

During drilling, heavy drilling fluids or "drilling muds" are pumped down the drill stem and forced out through jets in the bit. The drilling mud returns to the surface through the space between the borehole wall and the drill stem, carrying with it the drill cuttings drilled out by the bit. The drill cuttings are removed from the mud by a solids control system (which can include shakers, centrifuges and other specialized equipment) and disposed of in an environmentally sound manner. The solids control system permits the mud, which is often comprised of expensive chemicals, to be continuously reused and re-circulated back into the hole.

Through its Rig Systems segment, the Company sells the large "mud pumps" that are used to pump drilling mud through the drill stem. Through its Wellbore Technologies segment, the Company sells and rents solids control equipment; and provides solids control, waste management and drilling fluids services. Many operators internally coat the drill stem to improve its hydraulic efficiency and protect it from corrosive fluids sometimes encountered during drilling, and inspect and assess the integrity of the drill pipe from time to time. The Company manufactures and sells drill pipe and provides drill pipe inspection, coating, and "hardbanding" services through its Wellbore Technologies segment.

As the hole depth increases, the kelly must be removed frequently so that additional 30-foot joints of drill pipe can be added to the drill stem. When the bit becomes dull or the equipment at the bottom of the drill stem – including the drilling motors – otherwise requires servicing, the entire drill stem is pulled out of the hole and disassembled by disconnecting the joints of drill pipe. These are set aside or "racked," the old bit is replaced or service is performed, and the drill stem is reassembled and lowered back into the hole (a process called "tripping"). During drilling and tripping operations, joints of drill pipe must be screwed together and tightened ("made up"), and loosened and unscrewed ("spun out"). The Rig Systems segment provides drilling equipment to manipulate and maneuver the drill pipe in this manner. When the hole has reached certain depths, all of the drill pipe is pulled out of the hole and larger diameter pipe known as casing is lowered into the hole and permanently cemented in place in order to protect against collapse and contamination of the hole. The casing is typically inspected before it is lowered into the hole, a service the Wellbore Technologies segment provides. The Completion & Production Solutions segment manufactures pressure pumping equipment that is used to cement the casing in place.

The raising and lowering of the drill stem while drilling or tripping, and the lowering of casing into the wellbore, is accomplished with the rig's hoisting system. A conventional hoisting system is a block and tackle mechanism that works within the drilling rig's derrick. The lifting of this mechanism is performed via a series of pulleys that are attached to the drawworks at the base of the derrick. The Rig Systems segment sells and installs drawworks and pipe hoisting systems. During the course of normal drilling operations, the drill stem passes through different geological formations, which exhibit varying pressure characteristics. If this pressure is not contained, oil, gas and/or water would flow out of these formations to the surface.

The two means of containing these reservoir pressures are (i) primarily the circulation of drilling muds while drilling and (ii) secondarily the use of blowout preventers ("BOPs") should the mud prove inadequate in an emergency situation. The Rig Systems segment sells and services blowout preventers. Drilling muds are carefully designed to exhibit certain qualities that optimize the drilling process. In addition to containing formation pressure, they must (i) provide power to the drilling motor, (ii) carry drilled solids to the surface, (iii) protect the drilled formations from being damaged, and (iv) cool the drill bit. Achieving these objectives often requires a formulation specific to a given well and can involve the use of expensive chemicals as well as natural materials, such as certain types of clay. The fluid itself is often oil or more expensive synthetic mud. Given this expense, it is highly desirable to reuse as much of the drilling mud as possible. Solids control equipment such as shale shakers, centrifuges, cuttings dryers, and mud cleaners help accomplish this objective. The Wellbore Technologies segment rents, sells, operates and services this equipment. Drilling muds are formulated based on expected drilling conditions. However, as the hole is drilled, the drill stem may encounter a high pressure zone where the mud density is inadequate to maintain sufficient pressure. Should efforts to "weight up" the mud in order to contain such a pressure kick fail, a blowout could result, whereby reservoir fluids would flow uncontrolled into the well. To prevent blowouts to the surface of the well, a series of high-pressure valves known as blowout preventers are positioned at the top of the well and, when activated, form tight seals that prevent the escape of fluids. When closed, conventional BOPs prevent normal rig operations. Therefore, the BOPs are activated only if drilling mud and normal well control procedures cannot safely contain the pressure.

The operations of the rig and the condition of the drilling mud are closely monitored by various sensors, which measure operating parameters such as the weight on the rig's hook, the incidence of pressure kicks, the operation of the drilling mud pumps, etc. Through its Rig Systems segment, the Company sells and rents drilling rig instrumentation packages that perform these monitoring functions.

After the well has reached its total depth and the final section of casing has been set, the drilling rig is moved off of the well and the well is prepared to begin producing oil or gas in a process known as "well completion." Well completion usually involves installing production tubing concentrically in the casing. Due to the corrosive nature of many produced fluids, production tubing is often inspected and coated, services offered by the Wellbore Technologies segment. Sometimes operators choose to use corrosion resistant composite materials, which the Company also offers through its Completion & Production Solutions segment, or corrosion-resistant alloys, or operators sometimes pump fluids into wells to inhibit corrosion.

From time to time, a producing well may undergo workover procedures to extend its life and increase its production rate. Workover rigs are used to disassemble the wellhead, tubing and other completion components of an existing well in order to stimulate or remediate the well. Workover rigs are similar to drilling rigs in their capabilities to handle tubing, but are usually smaller and somewhat less sophisticated. The Company offers a comprehensive range of workover rigs through its Rig Systems segment. Tubing and sucker rods removed from a well during a well remediation operation are often inspected to determine their suitability to be reused in the well, which is a service the Wellbore Technologies segment provides.

Frequently, coiled tubing units or wireline units are used to accomplish certain well remediation operations or well completions. Coiled tubing is a recent advancement in petroleum technology consisting of a continuous length of reeled steel tubing which can be injected concentrically into the production tubing all the way to the bottom of most wells. It permits many operations to be performed without disassembling the production tubing, and without curtailing the production of the well. Wireline winch units are devices that utilize single-strand or multi-strand wires to perform well remediation operations, such as lowering tools and transmitting data to the surface. Through the Completion & Production Solutions segment, the Company manufactures and sells various types of coiled tubing equipment and coiled tubing and wireline equipment and tools.

Rig Systems

The Company's Rig Systems segment makes and supports the capital equipment and integrated systems needed to drill oil and gas wells on land and offshore. The segment designs, manufactures, and sells land rigs, complete offshore drilling equipment packages, and drilling rig components that mechanize and automate many complex rig construction processes.

Equipment and technologies in Rig Systems include: power transmission systems, like drives and generators; substructures, derricks, and masts; pipe lifting, racking, rotating, and assembly systems; pressure control equipment, including blowout preventers; cranes; and rig instrumentation and control systems.

Land Rig Packages. The Company designs, manufactures, assembles, upgrades, and supplies equipment sets to a variety of land drilling rigs, including those specifically designed to operate in harsh environments such as the Arctic Circle and the desert. Our key land rig product names include the *Drake™ Rig*, *Ideal™ Rig* and *Rapid Rig* ™. The Company's recent rig packages are designed to be safer and fast moving, to utilize AC technology, and to reduce manpower required to operate a rig.

Top Drives. The TDS™ Top Drive Drilling System, originally introduced by the Company in 1982, significantly alters the traditional drilling process. The TDS rotates the drill stem from its top, rather than by the rotary table, with a large electric motor affixed to rails installed in the derrick that traverses the length of the derrick to the rig floor. Therefore, the TDS eliminates the use of the conventional rotary table for drilling. Components of the TDS also are used to connect additional joints of drill pipe to the drill stem during drilling operations, enabling drilling with three joints of drill pipe compared to traditionally drilling with one joint of drill pipe. Additionally, the TDS facilitates horizontal and extended reach drilling.

Electric Rig Motors. The Company has helped lead the application of AC motor technology in the oilfield industry. The Company buys motors from third parties and builds them in its own facilities and is further developing motor technology, including the introduction of permanent magnet motor technology to the industry. These permanent magnet motors are being used in top drives, cranes, mud pumps, winches, and drawworks.

Rotary Equipment. The alternative to using a TDS to rotate the drill stem is to use a rotary table, which rotates the pipe at the floor of the rig. Rig Systems produces rotary tables as well as kelly bushings and master bushings for most sizes of kellys and makes of rotary tables. In 1998, the Company introduced the Rotary Support Table for use on rigs with a TDS. The Rotary Support Table is used in concert with the TDS to completely eliminate the need for the larger conventional rotary table.

Pipe Handling Systems. Pipe racking systems are used to handle drill pipe, casing and tubing on a drilling rig. Vertical pipe racking systems move drill pipe and casing between the well and a storage ("racking") area on the rig floor. Horizontal racking systems are used to handle tubulars while stored horizontally (for example, on the pipe deck of an offshore rig) and transport tubulars up to the rig floor and into a vertical position for use in the drilling process.

Vertical pipe racking systems are used predominantly on offshore rigs and are found on almost all floating rigs. Mechanical vertical pipe racking systems greatly reduce the manual effort involved in pipe handling. Pipe racking systems, introduced by the Company in 1985, provide a fully automated mechanism for handling and racking drill pipe during drilling and tripping operations, spinning and torquing drill pipe, and automatic hoisting and racking of disconnected joints of drill pipe. These functions can be integrated via computer controlled sequencing, and operated by a driller in an environmentally secure cabin. An important element of this system is the Iron Roughneck, which was originally introduced by the Company in 1976 and is an automated device that makes pipe connections on the rig floor and requires less direct involvement of rig floor personnel in potentially dangerous operations. The Automated Roughneck is an automated microprocessor-controlled version of the Iron Roughneck.

Horizontal pipe transfer systems were introduced by the Company in 1993. They include the Pipe Deck Machine ("PDM"), which is used to manipulate and move tubulars while stored in a horizontal position; the Pipe Transfer Conveyor ("PTC"), which transports sections of pipe to the rig floor; and a Pickup Laydown System ("PLS"), which raises the pipe to a vertical position for transfer to a vertical racking system. These components may be employed separately, or incorporated together to form a complete horizontal racking system, known as the Pipe Transfer System ("PTS").

Pipe Handling Tools. The Company's pipe handling tools are designed to enhance the safety, efficiency and reliability of pipe handling operations. Many of these tools have provided innovative methods of performing the designated task through mechanization of functions previously performed manually. The Rig Systems segment manufactures various tools used to grip, hold, raise, and lower pipe, and in the making up and breaking out of drill pipe, workstrings, casing and production tubulars including spinning wrenches, manual tongs, torque wrenches and kelly spinners.

Mud Pumps. Mud pumps are high pressure pumps located on the rig that force drilling mud down the drill pipe, through the drill bit, and up the space between the drill pipe and the drilled formation (the “annulus”) back to the surface. These pumps, which generate pressures of up to 7,500 psi, must therefore be capable of displacing drilling fluids several thousand feet down and back up the well bore. The conventional mud pump design, known as the triplex pump, uses three reciprocating pistons oriented horizontally. The Company has introduced the HEX™ Pump, which uses six pumping cylinders, versus the three used in the triplex pump. Along with other design features, the greater number of cylinders reduces pulsations (or surges) and increases the output available from a given footprint. Reduced pulsation is desirable where downhole measurement equipment is being used during the drilling process, as is often the case in directional drilling.

Hoisting Systems. Hoisting systems are used to raise or lower the drill stem while drilling or tripping, and to lower casing into the wellbore. The drawworks is the heart of the hoisting system. It is a large winch that spools off or takes in the drilling line, which is in turn connected to the drill stem at the top of the derrick. The drawworks also plays an important role in keeping the weight on the drill bit at a desired level. This task is particularly challenging on offshore drilling rigs, which are subject to wave motion. To address this, the Company has introduced the AHD™ Active Heave Drilling Drawworks. The AHD Drawworks uses computer-controlled motors to compensate for the motion experienced in offshore drilling operations.

Cranes. The Company provides a comprehensive range of crane solutions, with purpose-built products for all segments of the oil and gas industry as well as many other markets. The Company encompasses a broad collection of brand names with international recognition, and includes a large staff of engineers specializing in the design of cranes and related equipment. The product range extends from small cargo-handling cranes to the world’s largest marine cranes. In all, the Company provides over twenty crane product lines that include standard model configurations as well as custom-engineered and specialty cranes.

Motion Compensation Systems. Traditionally, motion compensation equipment is located on top of the drilling rig and serves to stabilize the bit on the bottom of the hole, increasing drilling effectiveness of floating offshore rigs by compensating for wave and wind action. The AHD Drawworks, discussed above, was introduced to eliminate weight and improve safety, removing the compensator from the top of the rig and integrating it into the drawworks system. In addition to the AHD Drawworks, the Company has introduced an Active Heave Compensation (“AHC”) System that goes beyond the capabilities of the AHD Drawworks to handle the most severe weather. Additionally, the Company’s tensioning systems provide continuous axial tension to the marine riser pipe (larger diameter pipe which connects floating drilling rigs to the well on the ocean floor) and guide lines on floating drilling rigs, tension leg platforms and jack-up drilling rigs.

Blowout Preventers (BOPs). BOPs are devices used to seal the space between the drill pipe and the borehole and, if necessary, to also shear the drill pipe itself to prevent blowouts (uncontrolled flows of formation fluids and gases to the surface). The Rig Systems segment manufactures a wide array of BOPs used in various applications from deepwater offshore vessels to land rigs. Ram and annular BOPs are back-up devices that are activated only if other techniques for controlling pressure in the wellbore are inadequate. When closed, these devices prevent normal rig drilling operations. Ram BOPs seal the wellbore by hydraulically closing rams (thick heavy blocks of steel) against each other across the wellbore. Specially designed packers seal around specific sizes of pipe in the wellbore, shear pipe in the wellbore or close off an open hole. Annular BOPs seal the wellbore by hydraulically closing a rubber packing unit around the drill pipe or kelly or by sealing against itself if nothing is in the hole.

In 1998, the Company introduced the NXT ™ ram type BOP which eliminates door bolts, providing significant weight, rig-time, and space savings. Its unique features make subsea operation more efficient through faster ram configuration changes. In 2004, the Company introduced the LXT ™ ram type of BOP, which features many of the design elements of the NXT ™, but is targeted at the land market. Over the past 5 years considerable focus has been placed on robustness and reliability in the fundamental design of the equipment with extensive testing being performed in the new R&D facility opened in 2012. In 2013, the Company acquired the T3 BOP product line further expanding its market offering of reliable, field proven designs for land based drilling applications.

The ShearMax™ line of low force BOP shear rams released in 2010 add substantial tubular shearing capability to the Company’s line of pressure control equipment, including the capability to shear large drill pipe tool joints, previously unheard of in the industry. This innovative shear blade design utilizes patented “Puncture Technology” to reduce the shearing pressures 50% or more and in some cases as much as five times lower. The ShearMax Blind shear provides a shear-and-seal design for drill pipe, while the Casing and TJC shears address casing up to 16” OD and most tool joints up to 2” wall thickness, respectively.

Derricks and Substructures. Drilling activities are carried out from a drilling rig. A drilling rig consists of one or two derricks; the substructure that supports the derrick(s); and the rig package, which consists of the various pieces of equipment discussed above. Rig Systems designs, fabricates and services derricks used in both onshore and offshore applications, and substructures used in onshore applications. The Rig Systems segment also works with shipyards in the fabrication of substructures for offshore drilling rigs.

Facilities. The Company's Rig Systems segment conducts manufacturing operations at major facilities in Houston, Galena Park, Sugar Land, Conroe, Cedar Park, Anderson, Fort Worth and Pampa, Texas; Duncan, Oklahoma; Orange, California; Edmonton, Canada; Aberdeen, Scotland; Kristiansand, Stavanger and Arendal, Norway; Etten-Leur and Groot-Ammers, the Netherlands; Carquefou, France; Singapore; Shanghai, China; Dubai, UAE; and Ulsan, South Korea. For a more detailed listing of significant facilities see Item 2. "Properties". The Rig Systems segment maintains sales and service offices in most major oilfield markets, either directly or through agents.

Customers and Competition. Rig Systems sells directly to drilling contractors, rig fabricators, well servicing companies, pressure pumping companies, national oil companies, major and independent oil and gas companies, and also through distribution companies. Demand for its products is strongly dependent upon capital spending plans by oil and gas companies and drilling contractors, and the level of oil and gas well drilling activity.

The products of the Rig Systems segment are sold in highly competitive markets and its sales and earnings can be affected by competitive actions such as price changes, new product development, or improved availability and delivery. The segment's primary competitors are Aker Solutions; American Electric Technologies; American Block; AXON Energy Products; Bentec (a division of Abbot Group); Bomco; Canrig (a division of Nabors Industries); Cavins Oil Well Tools; Cameron International; Coflexip (a division of Technip); Den-Con Tool Company; Forum Energy Technologies; General Electric; Global Energy Services; Hitec Products; Honghua; Huisman; Liebherr; Parveen Industries; Omron Corporation; Rolls Royce; Siemens; Stewart & Stevenson; Soilmec and Drillmec (a part of the Trevi Group); Seatrax; Tesco Corporation; Wärtsilä and Weatherford International. Management believes that the principal competitive factors affecting its Rig Systems segment are performance, quality, reputation, customer service, availability of spare parts and consumables, breadth of product line and price.

Rig Aftermarket

The Company's Rig Aftermarket segment provides comprehensive aftermarket products and services to support land rigs and offshore rigs, and drilling rig components manufactured by the Rig Systems segment.

The segment provides spare parts, repair, and rentals as well as technical support, field service and first well support, field engineering, and customer training through a network of aftermarket service and repair facilities strategically located in major areas of drilling operations.

The Rig Aftermarket segment primarily supports land and offshore drillers. Demand for Rig Aftermarket products and services primarily depends on overall levels of oilfield drilling activity, which drives demand for spare parts, service, and repair for Rig System's large installed base of equipment; and secondarily on drilling contractors' and oil and gas companies' capital spending plans, specifically capital expenditures on rig refurbishment and re-certification.

Spare Parts Rig Aftermarket maintains an inventory of spare parts manufactured by Rig Systems across a global network of aftermarket service and repair facilities.

Technical Support Rig Aftermarket's Technical Support Centers troubleshoot and resolve equipment needs for customers. Cross-disciplinary teams work together with field service technicians and subject matter experts to keep customers' rigs in operation and utilize web-based applications to record, manage, and resolve issues.

Field Service Field service engineers actively support rig equipment and technologies on location. Based across a global network of aftermarket service and repair facilities, field service engineers can be deployed to operating sites worldwide to resolve equipment issues, whether structural, mechanical, electrical, or software-related.

Repair Rig Aftermarket overhauls, repairs, rebuilds, and recertifies equipment to quality assurance and OEM specifications using only OEM parts.

eHawk Remote Support A subscription service available to customers, eHawk Support Centers provide support with fast issue response time. Using satellite and computer technology, eHawk Support Centers can diagnose equipment status and work to handle issues remotely, reducing service personnel visits to the field. eHawk utilizes web-based applications to record, manage, and resolve issues.

Field Engineering Rig Aftermarket Field Engineering supports customers by providing rig-specific designs, modifications, and solutions as needed. Services include rig surveys, proposal and design drawings, service manuals, and equipment installation.

Training Centers and Technical Colleges Rig Aftermarket Training Centers train customers on equipment and technologies, offering training for all equipment designed and manufactured by the Rig Systems segment. Training centers offer a varied a curriculum that incorporates hands-on experience, use of equipment simulators, automated classrooms, and enhanced animations with cross-sectional cutouts.

Wellbore Technologies

The Company's Wellbore Technologies segment designs, manufactures, rents, and sells a variety of equipment and technologies used to perform drilling operations, and offers services that optimize their performance, including: solids control and waste management equipment and services, drilling fluids, premium drill pipe, wired pipe, tubular inspection and coating services, instrumentation, downhole tools, and drill bits.

The Wellbore Technologies segment focuses on oil and gas companies and supports drilling contractors, oilfield service companies, and oilfield rental companies. Demand for Wellbore Technologies products and services primarily depends on the level of oilfield drilling activity by oil and gas companies, drilling contractors, and oilfield service companies.

The Company's customers rely on tubular inspection services to avoid failure of tubing, casing, flowlines, pipelines and drill pipe. Such tubular failures are expensive and in some cases catastrophic. The Company's customers rely on internal Tubular inspection and coating services are used most frequently in operations in high-temperature, deep, corrosive oil and gas environments. In selecting a provider of tubular inspection and tubular coating services, oil and gas operators consider such factors as reputation, experience, technology of products offered, reliability and price.

The Wellbore Technologies segment also provides products and services that are used in the course of drilling oil and gas wells. The NOV Downhole business sells and rents bits, drilling motors and specialized downhole tools that are incorporated into the drill stem during drilling operations, and are also used during fishing, well intervention, re-entry, and well completion operations. The Wellsite Services business provides products and services such as drilling fluids, highly-engineered solids control equipment, waste handling and treatment, completion fluids, power generation equipment, and other ancillary well site equipment and services. Wellsite Services is also engaged in barium sulfate ("barite") mining operations in Nevada. Barite is an inert powder material used as the primary weighting agent in drilling fluids. Additionally, efficient separation of drill cuttings enables the re-use of often costly drilling fluids.

Drill Pipe Products. As a result of its April 2008 acquisition of Grant Prideco, the Company designs, manufactures, and sells a full range of proprietary and API drill stem products used for the drilling of oil and gas wells. The principal products sold by Drill Pipe Products are: (i) drill pipe, (ii) heavy weight drill pipe, (iii) drill collars, and (iv) drill stem accessories. Drill pipe is the principal tool, other than the rig, required for the drilling of an oil or gas well. Its primary purpose is to connect the above-surface drilling rig to the bottom-hole assembly and the drill bit. A drilling rig will typically have an inventory of 10,000 to 30,000 feet of drill pipe depending on the size and service requirements of the rig. Joints of drill pipe have tool joints welded on each end to join the joints together to form what is commonly referred to as the drill string or drill stem.

In a vertical well, drill collars are used in the drilling process to place weight on the drill bit for better control and penetration. Drill collars are located directly above the drill bit and are manufactured from a solid steel bar to provide necessary weight.

Heavy weight drill pipe is a thick-walled seamless tubular product that is less rigid than a drill collar. In a vertical well, a few joints of heavy weight drill pipe is placed above the drill collars to provide a gradual transition between the heavier drill collars and the lighter drill pipe. When drilling horizontal or extended reach wells, several joints of heavy weigh drill pipe are placed high in the drill stem to push the drill pipe through the horizontal section of the well.

During the drilling process, motors mounted on the rig rotate the drill pipe, bottom-hole assembly, and drill bit. In addition to driving the drill bit, drill pipe serves as the conduit for drilling fluids to reach the drill bit. Drilling fluids are important as they cool and lubricated the bit and return the cuttings to the surface. Drill pipe is a consumable good. Depending on drilling conditions drill pipe can be used for the drilling of multiple wells. However, an active drill rig will continually wear out drill pipe which must be replaced.

In recent years, the depth and complexity of the wells customers drill, as well as the specifications and requirements of the drill pipe they purchase, have substantially increased. A majority of the drill pipe sold is required to meet specifications exceeding minimum API standards. The Company offers a broad line of premium drilling products designed for the high torque drilling of extended reach, directional, horizontal, deepwater, and ultra-deep wells in both international and domestic drilling markets. The Company's premium drilling products include its proprietary lines of uSeries™, XT™ and TurboTorque™ connections, higher strength and high toughness drill pipe, sour service drill pipe, and large diameter drill pipe that delivers hydraulic performance superior to standard sizes.

Tubular Coating. The Company develops, manufactures and applies its proprietary tubular coatings, known as Tube-Kote® coatings, to new and used downhole tubulars and line pipe. Tubular coatings help prevent corrosion by providing a shield to isolate the steel substrate from corrosive oilfield environments containing corrosive species such as CO_2 , H_2S and aqueous brines. Mitigating corrosion extends the life of tubular assets, reducing the frequency of well remediation caused by corrosion failures and leaks and reduces expensive interruptions in production. In addition, coatings are designed to increase the fluid flow rate through tubulars by decreasing the effective surface roughness allowing for flow increases up to and exceeding 25%. Additionally, the coatings mitigate the ability of paraffin, asphaltenes and scales from tightly adhering to the tubular internal surface. The Company prides itself on an industry recognized history of producing and applying the highest quality coating systems available on the global market.

In addition to the Company's TK™coatings, it also has complementary corrosion control products and services including TK Liners, Tubo-Wrap™, and KC-IPC Connections. TK Liners are fiberglass-reinforced tubes which are installed into steel line pipe. This safeguards the pipe against corrosion and extends the life of the tubular asset. In conjunction with the Thru-Kote™ connection system customers can weld a sleeve for a continuous internally coated pipeline system. Tubo-Wrap is a high performance external coating that protects the pipe from corrosion while in service. A unique aspect of Tubo-Wrap is its ability to mitigate handling and installation damage yielding a greater level of corrosion protection in downhole tubular and line pipe applications. KC-IPC Connections use a modified American Petroleum Institute ("API") coupling to create a "gas-tight" seal that prevents corrosion and turbulence in the critical connections of tubulars while protecting the internal plastic coating at the highly loaded contact points.

Tubular Inspection. Newly manufactured pipe sometimes contains serious defects that are not detected at the mill. In addition, pipe can be damaged in transit and during handling prior to use at the well site. As a result, exploration and production companies often have new tubulars inspected before they are placed in service to reduce the risk of tubular failures during drilling, completion, or production of oil and gas wells. Used tubulars are inspected by the Company to detect service-induced flaws after the tubulars are removed from operation. Used drill pipe and used tubing inspection programs allow operators to replace defective lengths, thereby prolonging the life of the remaining pipe and saving the customer the cost of unnecessary tubular replacements and expenses related to tubular failures.

Tubular inspection services employ all major non-destructive inspection techniques, including electromagnetic, ultrasonic, magnetic flux leakage and gamma ray. These inspection services are provided both by mobile units which work at the wellhead as used tubing is removed from a well, and at fixed site tubular inspection locations. The Company provides an ultrasonic inspection service for detecting potential fatigue cracks in the end area of used drill pipe, the portion of the pipe that traditionally has been the most difficult to inspect. Tubular inspection facilities also offer a wide range of related services, such as API thread inspection, ring and plug gauging, and a complete line of reclamation services necessary to return tubulars to useful service, including tubular cleaning and straightening, hydrostatic testing and re-threading.

In addition, the Company applies hardbanding material to drill pipe, to enhance its wear characteristics and reduce downhole casing wear as a result of the drilling process. In 2002, the Company introduced its proprietary line of hardbanding material, TCS 8000. The Company also cleans, straightens, inspects and coats sucker rods at 11 facilities throughout the Western Hemisphere. Additionally, new sucker rods are inspected before they are placed into service, to avoid premature failure, which can cause the oil well operator to have to pull and replace the sucker rod.

Machining Services. In 2005, the Company acquired Turner Oilfield Services and expanded our product offering into thread repair, tool joint rebuilding and sub manufacturing. Since then the Company has made strategic acquisitions of Hendershot and Mid-South and has expanded its machining services internally to develop a "one-stop-shop" concept for its drill pipe customers. Thread repair services include rotary shouldered and premium connections. The Company is licensed to perform thread repair services for API and proprietary connections. Tool joint rebuilding is a unique process to restore worn drill pipe tool joints, drill collars and heavy weight drill pipe to the original specifications to extend the service life of those assets. The Company manufactures downhole tools and is API licensed for this process in several locations.

In November 2009, the Company acquired South Seas Inspection (S) Pte. Ltd., ("SSI") and certain assets of its Brazilian affiliate. SSI provides a wide array of oilfield services including rig and derrick construction, derrick inspection and maintenance, drops surveys and load testing at the rig through the use of rope access technicians. This acquisition adds multiple new services and allows the Company to grow this business by leveraging existing relationships and infrastructure. These operations are based out of Singapore with branch offices in Baku, Azerbaijan and Aktau, Kazkhstan as well as a representative office in Vietnam. The highly trained workforce is completely mobile and provides these services worldwide.

Mill Systems and Sales. The Company engineers and fabricates inspection equipment for steel mills, which it sells and rents. The equipment is used for quality control purposes to detect defects in the pipe during the high-speed manufacturing process. Each piece of mill inspection equipment is designed to customer specifications and is installed and serviced by the Company.

NOV Downhole. The NOV Downhole business unit combines a wide array of drilling and intervention tool product lines with the drill bit, coring services, borehole enlargement and drilling dynamics/drilling optimization service lines previously consolidated within the ReedHycalog business unit of Grant Prideco.

The broad spectrum of bottom hole assembly ("BHA") components offered by NOV Downhole is unique within the industry and is the result of the strategic consolidation of several key acquisitions, including: NQL Energy Services, Inc., a leading manufacturer and provider of downhole drilling tools; Gammaloy Holdings, L.P., a manufacturer and provider of non-magnetic drill collars and other related products; Robbins & Myers, a manufacturer and provider of power section, and the ReedHycalog, Corion, and Andergauge business units of Grant Prideco, a global leader in the design, manufacture and provision of drill bits, variable gauge stabilizers, hydraulically and mechanically actuated under-reamers, specialty coring services and downhole vibration mitigation services.

NOV Downhole manufactures fixed cutter and roller cone drill bits and services its customer base through a technical sales and marketing network in virtually every significant oil and gas producing region of the world. It provides fixed-cutter bit technology under various brand names including Seeker™ directional drill bits, Fusetek™ hybrid drill bits, DuraDiamond™ impregnated bits and Titan™ Ultra aimed at larger bit applications. One of its most important fixed cutter drill bit innovations is a patented manufacturing process that has significantly enhanced the capability of polycrystalline diamond (PDC) cutters. The TReX™, Raptor™, Duraforce™ XD and Helios™ family of cutter technologies increase abrasion resistance (wear life) and thermal abrasion resistance without sacrificing impact resistance (toughness). This technology provides a diamond surface that maintains a sharp, low-wear cutting edge, producing drilling results that exceed conventional standards for PDC bit performance. The Company licenses its manufacturing process to most other providers of PDC bits.

The Company produces roller-cone bits for a wide variety of oil, gas and geothermal drilling applications. Roller-cone bits consist of three rotating cones that have cutting elements, which penetrate the formation through a crushing action as the cones rotate in conjunction with the rotation of the drill pipe or drive system. This cutting mechanism is more suitable than that of fixed cutter bits when drilling large holes, very soft shales, harder formations, or where the geology is changing. NOV Downhole manufactures roller-cone bits with milled teeth for soft formations and with tungsten carbide inserts for harder formations. It also manufactures a unique patented line of bits using a powder-metal forging technology, sold under the brand TuffCutter™. It markets its roller-cone products and technology globally under various brand names including RockForce™, Titan and TuffCutter.

NOV Downhole designs, manufacturers and services a wide array of downhole motors used in straight hole, directional, slim hole, and coiled tubing drilling applications. These motors are sold or leased under the NOV Downhole brand name. The Company also maintains a wide variety of motor power sections, including its proprietary PowerPlus™ and HemiDril™ and Robbins and Myers ERT™ rotors and stators which it incorporates into its own motors as well as sells to third parties. Downhole drilling motors utilize hydraulic horsepower from the drilling fluid pumped down the drill stem to develop torque at the bit. Motors are capable of achieving higher rotary velocities than can generally be achieved using conventional surface rotary equipment. Motors are often used in conjunction with high speed PDC bits to improve rates of penetration.

A key growth segment interlinked with the drilling motor business is Power Sections. NOV Downhole is one of the largest Power Section providers globally with the broadest portfolio of technology enabling drilling efficiency advances for every market segment. Our global Power Section manufacturing and supply footprint enables improved asset utilization for our customers by shortening service deliveries times. The Power Section Product Line sells products (rotors and stators) and services (relines for stators and re-surfacing for rotors) to 3rd party customers and the NOV Downhole motor rental fleet. This is offered for both Conventional and ERT Power Sections.

With the natural evolution of mature fields around the world, NOV Downhole is well positioned to address the sustained growth of Intervention and Well Workovers with a comprehensive offering of industry leading Bowen™ Brand Fishing and Thru-Tubing Tools. We sell and rent Fishing and Thru-Tubing tools to perform retrieval of stuck tools, remove debris, mill bridge plugs and other devices, cut and retrieve tubing and casing, manipulate well flow control devices and much more. Our recently launched TERRAFORCE™ combination Coiled Tubing Milling Jar is proving to be one of our most successful product launches although that can be largely attributed to plug milling work in hydraulically fractured wells.

With the unparalleled growth we have seen in the unconventional hydrocarbons segment over the last decade, the need for our customers to be able to work the BHA to bottom in long horizontal sections has proved to be crucial. This is why we have seen unheralded growth and phenomenal demand for NOV's AGITATOR™ axial oscillation tool, most notably in the North American shale plays. The AGITATOR™ oscillation tool gently oscillates the Bottom Hole Assembly to significantly improve weight transfer and reduce friction. This improves weight transfer and reduces stick-slip in all modes of drilling, but especially when oriented drilling with a steerable motor. The AGITATOR™ oscillation tool provides BHA excitement to improve weight transfer to the bit. Extends the boundaries of extended reach and horizontal drilling with motors. The AGITATOR™ tool has also been similarly successful when deployed on Coiled Tubing to enable optimum weight-on-tool perform post-fracturing milling and well cleanout work. Additionally a new application of Fishing-with-AGITATOR and associated tools is now proliferating worldwide with very high levels of success, the attributes of the AGITATOR™ (i.e. low impact, high frequency,) ideally compliments the high impact low frequency of traditional fishing jars.

NOV Downhole also manufactures and sells drilling jars, shock tools, bumper subs and a range of other conventional drilling tools such as non-magnetic drill collars. Drilling jars are placed in the drill string, where they can be used to generate a sudden, jarring motion to free the drill string should it become stuck in the wellbore during the drilling process. This jarring motion is generated using hydraulic and/or mechanical force provided at the surface.

Through its Coring Services business line, NOV Downhole offers coring solutions that enable the extraction of actual rock samples from a drilled well bore and allow geologists to examine the formations at the surface. One of the coring services utilized is the Company's unique Corion Express™ system which allows the customer to drill and core a well without tripping pipe. Corion Express utilizes wireline retrievable drilling and coring elements which allow the system to transform from a drilling assembly to a coring assembly and also to wireline retrieve the geological core. This capability enables customers to save significant time and expense during the drilling and coring process.

NOV Downhole offers a wide variety of industry leading technologies to enable customers to enlarge the diameter of a drilled hole below a restriction (typically a casing string) via its Borehole Enlargement business line. Borehole enlargement services are typically utilized in deep water drilling where customers wish to maximize the size of each successive casing string in order to preserve a relatively large completion hole size through which to produce hydrocarbons from the reservoir. Borehole enlargement is also employed where customers wish to reduce the fluid velocity and pressure within the well-bore annulus to reduce the risk of formation erosion or accidental fracture. Borehole Enlargement provides bi-centered drill bits, expandable reamers (marketed under the AnderReamer™ brand name) and associated equipment along with well-site service technicians who deliver 24 hour support during hole enlargement operations.

The Integrated Solutions & Optimization group combines two initiatives to add more value to the NOV Downhole portfolio – the ADS expertise in downhole vibration measurement analysis, and the Strategic Integrated Solution methodology for establishing a systems approach to solving client challenges. This high performing Team uses optimization tools and personnel to establish value differentiation between NOV Downhole products and those of the competition. The focus is on the client needs and buying habits, with the intent of maximizing our participation in the current market and being the preferred supplier in a down market. This approach can be utilized strategically within 'conventional' districts to grow revenue / market share, but also is a key foundation for the overall Tiered Solutions strategy where we start to supply solutions to drilling challenges, not just tools.

NOV Downhole manufactures, sells and rents electronic tools (eTools) to provide directional and drilling dynamics data to the drilling service companies and O&G Operators while they are drilling a well. Directional Sensors, Steering Tools, Magnetic Multi-shot Tools and Electromagnetic Measurement-While-Drilling Systems are produced by NOV Downhole. These directional eTools, provide a downhole measurement of the azimuth (Magnetic North), well inclination and tool face measurements and store the data in memory or utilize a telemetry pathway (mud pulse, conductive wireline, electromagnetic or Intelliserv Wired Drill Pipe) to transmit the downhole data to the surface. The drilling dynamics tools measures downhole vibration, weight, torque, pressure, temperature, bending and rotational speed and either stores the data in memory or utilizes a telemetry pathway to get the downhole data to the surface. At the surface this data is analyzed and utilized to optimize the well trajectory and to improve the drilling rate-of-penetration by minimizing the bottom hole assembly vibration and by optimizing the drilling weight, torque and RPM.

NOV Downhole Managed Pressure Drilling (MPD) is a newly formed team to support the drilling challenges of our customers and further safety and efficiency to the industry by offering an array of products from NOV Downhole and as well as other business segments of NOV. MPD utilizes specialty equipment and support services to enable improved kick detection and as well broaden the obtainable reserves of many clients by using chokes, manifolds, rotating control devices, continuous circulation systems, downhole sensors and optimized control systems. Applications of the technology are in use within the shale gas fields to ultra-deep-water and expanding rapidly.

Solids Control and Waste Management. The Company develops and manufactures highly-engineered equipment, products and services for the purpose of separating and managing drill cuttings produced by the drilling process ("Solids Control"). Drill cuttings are usually contaminated with petroleum or drilling fluids, and must be disposed of in an environmentally sound manner. Solids control systems offered by Wellsite Services typically consist of five primary stages of separation: shale shakers, vacuum degasser, desander, desilter and centrifuge, each of which is able to provide a finer degree of separation. Wellsite Services through its Brandt products group manufactures state-of-the-art patented equipment such as the Brandt King Cobra™ and VSM Multi-Sizer™ which utilizes one-of-a-kind Constant G-Control (CGC). Upon the separation of the drill cuttings Wellsite Services is able to employ several waste management services such as transport and storage, where we utilize conveyor systems, FREEFLOW™ positive pressure systems, custom transfer systems and various discharge vessels. When treatment of the waste is required Wellsite Services has an array of services available for any required application from dewatering, cuttings drying, cuttings injection, desalination, indirect thermal desorption and hot oil thermal desorption. Wellsite Services products and systems allow our customers to maintain environmental stewardship through the proper treatment, transport and disposal of drilling waste.

Fluids Services. The Company is engaged in the provision of drilling fluid systems, drilling fluid products, completion fluids and other related services. This division is also engaged in barite mining operations. Drilling fluids are designed and used to maintain well bore stability while drilling, control downhole pressure, drill bit lubrication, suspend and release cuttings, transmit hydraulic energy to drilling tools and bit and as a drill cuttings displacement medium. Drilling fluid systems are typically classified as dispersed water-based) and non-dispersed (oil-based). Wellsite Services provides both types of drilling fluid systems, specializing in developing the right system for the application. POLYTRAXX™ is an example of a unique fluid system developed by Wellsite Services offering comparable drilling performance to oil-based systems without the same environmental challenges.Completion fluids are used to clean the well bore and stimulate production.

Portable Power. The Portable Power division provides rental equipment for use in the upstream oil and gas industry, refinery and petrochemical, construction, events, disaster relief and other industries. Generator sizes range from 15kw up to 1250kw and Portable Power has the engineering expertise to parallel units to accommodate larger load requirements for offshore and deepwater projects. Natural Gas generators which can be run directly by well gas are available and help to offset large fuel and associated transportation costs. HVAC units from 12.5 ton to 50 ton are available for general use and explosion proof units from 40 ton to 80 ton are targeted for petrochemical plants, refineries, offshore drilling rigs and other manufacturing applications which require this safety standard. Larger Chiller units up to 500 ton are available for large scale construction or disaster relief applications such as Hurricane Sandy, where Portable Power chillers, generators and dehumidifiers were used on a large scale. Through the Construction division, Portable Power offers custom built diesel generator packages and electrical distribution along with many other items that complement our rental services for the offshore industry. Portable Power also has highly trained generator technicians and offshore electricians available for custom design and hookup required for many offshore projects.

Instrumentation. The Company's Instrumentation business provides drilling rig operators real time measurement and monitoring of critical parameters required to improve rig safety and efficiency. In 1999, the Company introduced its RigSenseTM Wellsite Information System, which combines leading hardware and software technologies into an integrated drilling rig package. Access of drilling data is provided to offsite locations, enabling company personnel to monitor drilling operations from an office environment, through a secure link. Systems are both sold and rented, and are comprised of hazardous area sensors placed throughout the rig to measure critical drilling parameters; all networked back to a central command station for review, recording and interpretation. The Company offers unique business integration services to directly integrate information into business applications that improves accuracy and assists drilling contractors in managing their drilling business. Reports on drilling activities and processes are now provided from the rig site as a part of the DrillSuite™ business solution to allow contractors to streamline administration by eliminating manual entry of data, promotes accurate payroll processing and invoicing, and includes asset tracking and preventive maintenance management through its RigMS™ solution. The real time information provided also allows the Company to advance the drilling process using advanced drilling algorithms and electronic controls such as our Wildcat™ Auto Drilling System for better execution of the well plan, enhanced rates of penetration, reduced program costs, and improved wellbore quality. Complementing the Company's surface solutions is a portfolio of Down-Hole Instrumentation ("DHI") products for both straight-hole and directional markets. Key advancements in this area include the introduction of the Company's time saving E-Totco™ Electronic Drift Recorder, which serves as an electronic equivalent to the traditional mechanical drift tool that the Company has offered since 1929.

NOV IntelliServ. NOV IntelliServ is a joint venture between the Company and Schlumberger, Ltd. in which the Company holds a 55% interest and maintains operational control. NOV IntelliServ manufactures wellbore data transmission products that are used to deliver high-speed communication up and down the drill string throughout drilling and completion operations that are undertaken during the construction of oil and gas wells. NOV IntelliServ's core product, "The IntelliServTM Network", was commercialized in February 2006 and incorporates various proprietary mechanical and electrical components into the Company's premium drilling tubulars to enable data transmission rates that are orders of magnitude greater than conventional methods. This high speed telemetry enables the efficiency of various drilling and well activities to be increased, reducing drilling time and costs. The IntelliServ Network also permits virtually unlimited real-time actuation of drilling tools and sensors at the bottom of the drill string, a process that conventionally requires the time consuming return of tools to the surface. NOV IntelliServ sells and leases its products to drilling rig contractors, equipment rental companies and drilling service providers.

Voest-Alpine Tubulars ("VAT"). VAT is a joint venture between the Company and the Austrian based Voestalpine Group. The Company has a 50.01% investment in the joint venture which is located in Kindberg, Austria. VAT owns a tubular mill with an annual capacity of approximately 380,000 metric tons and is the primary supplier of green tubes for our U.S. based production. In addition to producing green tubes, VAT produces seamless tubular products for the OCTG market and non-OCTG products used in the automotive, petrochemical, construction, mining, tunneling and transportation industries.

VAT is accounted for under the equity-method of accounting due to the minority owner having substantive participating rights. Under a limited partnership operating agreement the Company has no rights to unilaterally take any action with respect to its investment and the day to day operations of VAT are under the direction of a Management Board, whose members are determined principally by the minority owner. The Management Board is responsible for planning, production, sales and general personal matters, which represent substantive participating rights that overcome the presumption that the Company should consolidate its 50.01% investment.

Customers and Competition. Customers for the Wellbore Technologies' products and services include major and independent oil and gas companies, national oil companies, drilling and workover contractors, oilfield equipment and product distributors and other manufacturers, oilfield service companies, steel mills, and other industrial companies. The Company's competitors include, among others, Baker Hughes; Drill Pipe Masters; Frank's International; Future Pipe; Halliburton; Hanwei; Hilong; Patterson Tubular Services; Precision Tube (a division of Tenaris); ShawCor; Schlumberger; Superior Energy Services; Texas Steel Conversion; Vallourec & Mannesmann and Weatherford International. In addition, the Company competes with a number of smaller regional competitors. Certain foreign jurisdictions and government-owned petroleum companies located in some of the countries in which the Company operates have adopted policies or regulations that may give local nationals in these countries certain competitive advantages. Within the Company's corrosion control products, certain substitutes such as non-metallic tubulars, corrosion inhibitors, corrosion resistant alloys, cathodic protection systems, and non-metallic liner systems also compete with the Company's products. Management believes that the principal competitive factors affecting this business are performance, quality, reputation, customer service, availability of products, spare parts and consumables, breadth of product line and price.

Completion & Production Solutions

The Company's Completion & Production Solutions segment integrates technologies for well completions and oil and gas production. The segment designs, manufactures, and sells equipment and technologies needed for hydraulic fracture stimulation, including pressure pumping trucks and pumps, blenders, sanders, hydration units, injection units, flowline, manifolds and wellheads; well intervention, including coiled tubing units, coiled tubing, and wireline units and tools; onshore production, including composite pipe, surface transfer and progressive cavity pumps, and artificial lift systems; and offshore production, including floating production systems and subsea production technologies.

The Completion & Production Solutions segment primarily supports service companies and oil and gas companies. Demand for Completion & Production Solutions products depends on the level of oilfield completions and workover activity by oilfield service companies and drilling contractors and capital spending plans by oil and gas companies and oilfield service companies.

This segment has benefited from several strategic acquisitions and other investments completed during the past few years, including additional operations in the United States, Canada, the United Kingdom, Brazil, Mexico, Russia, Argentina, India, the Netherlands, Singapore, Malaysia, and the United Arab Emirates.

Coiled Tubing Equipment. Coiled tubing consists of flexible steel tubing manufactured in a continuous string and spooled on a reel. It can extend several thousand feet in length and is run in and out of the wellbore at a high rate of speed by a hydraulically operated coiled tubing unit. A coiled tubing unit is typically mounted on a truck, semi-trailer or skid (steel frames on which portable equipment is mounted to facilitate handling with cranes for offshore use) and consists of a hydraulically operated tubing reel or drum, an injector head which pushes or pulls the tubing in or out of the wellbore, and various power and control systems. Coiled tubing is typically used with sophisticated pressure control equipment which permits the operator to perform workover operations on a live well. The Completion & Production Solutions segment manufactures and sells both coiled tubing units and the ancillary pressure control equipment used in these operations. Through its acquisition of Rolligon in late 2006, the Company enhanced its portfolio by adding additional pressure pumping and coiled tubing equipment products.

Currently, most coiled tubing units are used in well remediation and completion applications. The Company believes that advances in the manufacturing process of coiled tubing, tubing fatigue protection and the capability to manufacture larger diameter and increased wall thickness coiled tubing strings have resulted in increased uses and applications for coiled tubing products. For example, some well operators are now using coiled tubing in drilling applications such as slim hole re-entries of existing wells. The Company engineered and manufactured the first coiled tubing units built specifically for coiled tubing drilling in 1996.

Coiled tubing provides a number of significant functional advantages over the principal alternatives of conventional drill pipe and workover pipe. Coiled tubing allows faster "tripping," since the coiled tubing can be reeled quickly on and off a drum and in and out of a wellbore. In addition, the small size of the coiled tubing unit compared to an average workover rig or drilling rig reduces preparation time at the well site. Coiled tubing permits a variety of workover and other operations to be performed without having to pull the existing production tubing from the well and allows ease of operation in horizontal or highly deviated wells. Thus, operations using coiled tubing can be performed much more quickly and, in many instances, at a significantly lower cost. Finally, use of coiled tubing generally allows continuous production of the well, eliminating the need to temporarily stop the flow of hydrocarbons. As a result, the economics of a workover are improved because the well can continue to produce hydrocarbons and thus produce revenues while the well treatments are occurring. Continuous production also reduces the risk of formation damage which can occur when the flow of fluids is stopped or isolated. Under normal operating conditions, the coiled tubing string must be replaced every three to four months. The Company designs, manufactures, and sells coiled tubing under the Quality Tubing brand name at its mill in Houston, Texas.

Wireline Equipment. The Company's wireline products include wireline drum units, which consist of a spool or drum of wireline cable, mounted in a mobile vehicle or skid, which works in conjunction with a source of power (an engine mounted in the vehicle or within a separate "power pack" skid). The wireline drum unit is used to spool wireline cable into or out of a well, in order to perform surveys inside the well, sample fluids from the bottom of the well, retrieve or replace components from inside the well, or to perform other well remediation or survey operations. The wireline used may be "slick line", which is conventional single-strand steel cable used to convey tools in or out of the well, or "electric line", which contains an imbedded single-conductor or multi-conductor electrical line which permits communication between the surface and electronic instruments attached to the end of the wireline at the bottom of the well.

Wireline units are usually used in conjunction with a variety of other pressure control equipment which permits safe access into wells while they are flowing and under pressure at the surface. The Company engineers and manufactures a broad range of pressure control equipment for wireline operations, including wireline blowout preventers, strippers, packers, lubricators and grease injection units. Additionally, the Company makes wireline rigging equipment such as mast trucks.

Stimulation Equipment. The Company's stimulation products include fracturing pumps, acid units, frac blenders, combo units, hydration, chemical additive systems as well as services and parts. The Company acquired Enerflow Industries, Inc. ("Enerflow") in May 2012. Enerflow operates out of facilities in Calgary, AB and Tulsa, OK. Enerflow produces frac pumpers (including truck, trailer, and skid mounted units) as well as cementing units, acidizing units, nitrogen units, and small amounts of well servicing rigs, integrated mud systems and coiled tubing equipment.

Turret Mooring Systems. The Company acquired Advanced Production and Loading PLC ("APL"), in December 2010. APL, based in Norway, designs and manufactures turret mooring systems and other products for FPSOs and other offshore vessels and terminals. A turret mooring system consists of a geostatic part attached to the seabed and a rotating part integrated in the hull of the FPSO, which are connected and allow the ship to weathervane (rotate) around the turret.

Flexible Pipe Systems. The Company acquired NKT Flexibles I/S ("NOV Flexibles") in April 2012. NOV Flexibles designs and manufactures flexible pipe products and systems for the offshore oil and gas industry, including products associated with FPSO's and other offshore production platforms, as well as subsea production systems including flow-lines and flexible risers. The existing product range consists of flexible pipe solutions ranging from 2" – 16" (approx. 50 – 406 mm inside diameter) and designed to operate under very demanding offshore conditions in all parts of the world. The products are unique, because they remain flexible even under very high working pressure, up to 1,000 bars, and at the same time they are able to withstand working temperatures up to 130° centigrade. Flexible pipe systems are superior to other pipe solutions in respect of flexibility, ability to withstand different design conditions and capability to convey challenging mixtures of liquid and gaseous fluids.

Today, flexible pipe systems are used to recover oil and gas at water depths exceeding 2,000 meters, and NOV Flexibles' products are qualified for use in water depths down to 2,000 meters. NOV Flexibles also supplies a wide range of additional equipment to the market, such as accessories and steel structures required in a given system configuration.

Fiberglass & Composite Tubulars. When compared to conventional carbon steel and even corrosion-resistant alloys, resin-impregnated fiberglass and other modern plastic composites often exhibit superior resistance to corrosion. Some producers manage the corrosive fluids sometimes found in oil and gas fields by utilizing composite or fiberglass tubing, casing and line pipe in the operations of their fields. In 1997, the Company acquired Fiber Glass Systems, a leading provider of high pressure fiberglass tubulars used in oilfield applications, to further serve the tubular corrosion prevention needs of its customers. Fiber Glass Systems has manufactured fiberglass pipe since 1968 under the name Star ™, and was the first manufacturer of high-pressure fiberglass pipe to be licensed by the API in 1992. Through further acquisitions and investments in technologies, the Company has extended its fiberglass and composite tubing offering into industrial and marine applications, in addition to its oilfield market.

In 2011, the Company acquired Ameron International Corporation ("Ameron") which allowed it to expand its Fiberglass & Composite Tubulars business. See Note 4 to the Consolidated Financial Statements for information regarding acquisitions made by the Company in 2011. Ameron's Fiberglass-Composite Pipe business, which is now part of the Company's Fiber Glass Systems business, develops, manufactures and markets filament-wound and molded fiberglass pipe and fittings. These products are used by a wide range of process industries, including industrial, petroleum, chemical processing and petrochemical industries, and for service station piping systems, but predominantly aboard marine vessels, FPSOs and offshore oil platforms, and are marketed as an alternative to metallic piping systems which ultimately fail under corrosive operating conditions.

In 2012, the Company acquired Fiberspar Corporation ("Fiberspar"). See Note 4 to the Consolidated Financial Statements for information regarding acquisitions made by the Company in 2012. Fiberspar, which is now part of the Company's Fiber Glass Systems business, manufactures and sells fiberglass-reinforced spoolable pipe to the oil and gas industry. This fiberglass-reinforced spoolable pipe provides a reliable, corrosion-resistant, cost-effective solution for tubulars used during the production and transportation of oil and gas. Fiberspar has manufacturing plants in Houston, TX and Johnstown, Colorado, with 16 deployment centers (stocking locations) for its products in the U.S., Canada and Australia.

XL Systems. The Company's XL Systems product line offers the customer an integrated package of large-bore tubular products and services for offshore or deep onshore wells. This product line includes the Company's proprietary line of wedge thread connections on large-bore tubulars and related engineering and design services. The Company provides this product line for drive pipe, jet strings and conductor casing. The Company also produces large-bore tubulars with a high-strength, high-fatigue Viper™ weld-on connector for use in deep-water and other environments where an extremely robust connector is needed. The Company also offers service personnel in connection with the installation of all of these products.

Process and Flow Technologies. Process and Flow Technologies serves its customers in various industrial and oil and gas markets by design, manufacturing and distributing key products including Pumping Technologies (Reciprocating, Multistage Surface, and Progressive Cavity Pumps), Process Equipment (Dynamic Oil Recovery, Water Treatment, Sand Handling, Separation and Crude / Gas Handling), Artificial Lift Solutions (Stuffing Boxes, Drive Heads, PCP, Control Boxes, Polished Rod Accessories, and Hydraulic Pumping Units), Mixing and Agitation Equipment,, Pipeline Products (Closures, Expanding Gate Valves, and Plug Valves) and General Oilfield Products (Critical Service Hookups, Pumping Tees, and Production BOP's) This business is highly diversified through its presence in oil and gas and industrial markets, which include waste water treatment, mining, chemical processing, paper and pulp, agriculture, food and beverage, among others. The group supports its international market and customer base through a mixed channel to market model, which includes both direct sales and separate partnership relationships. Process and Flow Technologies is strengthening its offering across its product lines by adding new technologies that support its integrated packaging solutions strategy. The 2013 acquisition of Robbins & Myers included the addition of the Moyno™ product line to the Mono business, expanding the progressive cavity pump product line. Additionally, the acquisition expanded the business to include industrial mixing equipment, including mixers, agitators, and heat exchangers.

Pumps & Expendables. The Company's Pumps & Expendables business designs, manufactures, and sells pumps that are used in oil and gas drilling operations, well service operations, production applications, as well as industrial applications. These pumps include reciprocating positive displacement and centrifugal pumps. High pressure mud pumps are sold within the Completion & Production Solutions segment. These pumps are sold as individual units and unitized packages with drivers, controls and piping. The Company also manufactures fluid end expendables (liners, valves, pistons, and plungers) The Company offers popular industry brand names like Wheatley, Gaso, and Omega reciprocating pumps and Centrifugal Pumps.

The Company also manufactures a line of commodity and high end valves, chokes, wellhead, and flow line equipment used in both production, pipeline, and drilling applications. Additionally, these products are used to manufacture frac trees and manifolds which are both rented and sold, cement, and production manifolds. The Company manufactures its products in Houston and Odessa, Texas, Tulsa, Oklahoma, Houma, Louisiana, Newcastle, England and Buenos Aires, Argentina.

The company manufactures production process equipment such as heater treaters, tanks, pressure vessels, produced water treatment, and sand handling equipment. This is used in both onshore and offshore applications. This equipment is manufactured in Montrose, Scotland, Harvey, Louisiana, Odessa and San Angelo, Texas.

Industrial. The Industrial and Mixing Solutions business supplies products and services used in the chemical, construction, mining, and water industries, while increasing their presence in the oil and gas markets. This equipment is manufactured in Manchester and Derby, UK, Dayton and Springfield, Ohio, North Andover, Massachusetts, Claremore, Oklahoma, Melbourne, Australia, and Shanghai, China.

Customers and Competition. The primary customers for the products and services offered by the Completion & Productions Solutions segment include drilling contractors, well servicing companies, major and independent oil and gas companies, and national oil companies. Competitors in drilling services include Aggreko; Baker Hughes; Cameron International; Circor International; Corpro (a division of ALS); Halliburton; Hunting; Derrick Equipment Company; Fluid Systems; FMC Technologies; Forum Energy Technologies; Logan Oil Tools; Newpark Resources; Schoeller Bleckmann; Step OilTools; Technip; Varel; Ulterra Drilling Technologies; Roper Industries; Schlumberger; Southwest Oilfield Products and Weir Group. There are also a large number of regional competitors and in addition, the Completion & Production Solutions segment sells its products and services into highly competitive markets. Management believes that on-site support is becoming an important competitive element in this market, and that the principal competitive factors affecting the business are performance, quality, reputation, customer service, product availability and technology, breadth of product line and price.

2013 Acquisitions and Other Investments

On February 20, 2013, the Company completed its acquisition of all of the shares of Robbins & Myers ("R&M"), Inc., a U.S.-based designer and manufacturer of products and systems for the oil and gas industry. Under the merger agreement for this transaction, R&M shareholders received $60.00 in cash for each common share for an aggregate purchase price of $2,378 million, net of cash acquired.

The Company has included the financial results of R&M in its consolidated financial statements as of the date of acquisition with components of the R&M operations included in each of the Company's segments. The Company believes the acquisition of R&M will advance its strategic goal of providing a broader selection of products and services to its customers.

During 2013, in addition to Robbins & Myers, the Company made the following acquisitions:

Acquisition	Form	Operating Segment	Date of Transaction
Fidmash	Stock*	Completion & Production Solutions	April 2013
Novmash	Stock*	Completion & Production Solutions	April 2013
Itasco Precision Ltd.	Stock	Completion & Production Solutions	April 2013
BBJ Tools Inc.	Asset	Wellbore Technologies	June 2013
Moyno de Mexico S.A. de C.V.	Stock*	Completion & Production Solutions	August 2013

* Purchased the remaining portion of joint venture.

The Company paid an aggregate purchase price of $2,397 million, net of cash acquired for acquisitions in 2013.

Seasonal Nature of the Company's Business

Historically, the level of some of the Company's segments have followed seasonal trends to some degree. In general, the Rig Systems and Rig Aftermarket segments have not experienced significant seasonal fluctuation although orders for new equipment and aftermarket spare parts may be modestly affected by holiday schedules. There can be no guarantee that seasonal effects will not influence future sales in this segment.

In Canada, the Wellbore Technologies and Completion & Production Solutions segments typically realized high first quarter activity levels, as operators take advantage of the winter freeze to gain access to remote drilling and production areas. In past years, certain Canadian businesses within Wellbore Technologies and Completion & Production Solutions have declined during the second quarter due to warming weather conditions which resulted in thawing, softer ground, difficulty accessing drill sites, and road bans that curtailed drilling activity ("Canadian Breakup"). However, these segments have typically rebounded in the third and fourth quarter. Wellbore Technologies and Completion & Production Solutions activity in both the U.S. and Canada sometimes increases during the third quarter and then peaks in the fourth quarter as operators spend the remaining drilling and/or production capital budgets for that year. Wellbore Technologies and Completion & Production Solutions revenues in the Rocky Mountain region sometimes decline in the late fourth quarter or early first quarter due to harsh winter weather. The Company's fiberglass and composite tubulars business in China has typically declined in the first quarter due to the impact of weather on manufacturing and installation operations, and due to business slowdowns associated with the Chinese New Year.

The Company anticipates that the seasonal trends described above will continue. However, there can be no guarantee that spending by the Company's customers will continue to follow patterns seen in the past or that spending by other customers will remain the same as in prior years.

Marketing and Distribution Network

Substantially all of our Rig Systems capital equipment and Rig Aftermarket spare parts sales, and a large portion of our smaller pumps and parts sales, are made through our direct sales force and distribution service centers. Sales to foreign oil companies are often made with or through agent or representative arrangements. Products within Wellbore Technologies and Completion & Production Solutions are rented and sold worldwide through our own sales force and through commissioned representatives.

The Rig Systems and Rig Aftermarket segment's customers include drilling contractors, shipyards and other rig fabricators, well servicing companies, pressure pumpers, national oil companies, major and independent oil and gas companies, supply stores, and pipe-running service providers. The Rig Systems segment primarily supports land and offshore drillers. Demand for Rig Systems products primarily depends on drilling contractors' and oil and gas companies' capital spending plans, specifically capital expenditures on rig construction and refurbishment. The Rig Aftermarket segment primarily supports land and offshore drillers. Demand for Rig Aftermarket products and services primarily depends on overall levels of oilfield drilling activity, which drives demand for spare parts, service, and repair for Rig System's large installed base of equipment; and secondarily on drilling contractors' and oil and gas companies' capital spending plans, specifically capital expenditures on rig refurbishment and re-certification. Rig Systems and Rig Aftermarket purchases can represent significant capital expenditures, and are often sold as part of a rig fabrication or major rig refurbishment package. Sometimes these packages cover multiple rigs, and often the Company bids jointly with other related product and services providers, such as rig fabrication yards and rig design firms.

The Wellbore Technologies segment's customers are predominantly oil and gas companies, drilling contractors, oilfield service companies, and oilfield rental companies. Demand for Wellbore Technologies products and services primarily depends on the level of oilfield drilling activity by oil and gas companies, drilling contractors, and oilfield service companies.

The Completion & Production Solutions segment's customers are predominantly service companies and oil and gas companies. Demand for Completion & Production Solutions products depends on the level of oilfield completions and workover activity by oilfield service companies and drilling contractors and capital spending plans by oil and gas companies and oilfield service companies.

The Company's foreign operations, which include significant operations in Canada, Europe, the Far East, the Middle East, Africa and Latin America, are subject to the risks normally associated with conducting business in foreign countries, including foreign currency exchange risks and uncertain political and economic environments, which may limit or disrupt markets, restrict the movement of funds or result in the deprivation of contract rights or the taking of property without fair compensation. Government-owned petroleum companies located in some of the countries in which the Company operates have adopted policies (or are subject to governmental policies) giving preference to the purchase of goods and services from companies that are majority-owned by local nationals. As a result of such policies, the Company relies on joint ventures, license arrangements and other business combinations with local nationals in these countries. In addition, political considerations may disrupt the commercial relationship between the Company and such government-owned petroleum companies. Although the Company has not experienced any material problems in foreign countries arising from nationalistic policies, political instability, economic instability or currency restrictions, there can be no assurance that such a problem will not arise in the future. See Note 15 to the Consolidated Financial Statements for information regarding geographic revenue information.

Research and New Product Development and Intellectual Property

The Company believes that it has been a leader in the development of new technology and equipment to enhance the safety and productivity of drilling and well servicing processes and that its sales and earnings have been dependent, in part, upon the successful introduction of new or improved products. Through its internal development programs and certain acquisitions, the Company has assembled an extensive array of technologies protected by a substantial number of trade and service marks, patents, trade secrets, and other proprietary rights.

As of December 31, 2013, the Company held a substantial number of United States patents and had several patent applications pending. As of this date, the Company also had foreign patents and patent applications pending relating to inventions covered by the United States patents. Additionally, the Company maintains a substantial number of trade and service marks and maintains a number of trade secrets. Expiration dates of such patents range from 2014 to 2033. The Company does not expect significant adverse effects as patents expire.

Although the Company believes that this intellectual property has value, competitive products with different designs have been successfully developed and marketed by others. 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 as important as its intellectual property in its ability to compete. While the Company stresses the importance of its research and development programs, the technical challenges and market uncertainties associated with the development and successful introduction of new products are such that there can be no assurance that the Company will realize future revenues from new products.

Engineering and Manufacturing

The manufacturing processes for the Company's products generally consist of machining, welding and fabrication, heat treating, assembly of manufactured and purchased components and testing. Most equipment is manufactured primarily from alloy steel. The availability and price of alloy steel castings, forgings, purchased components and bar stock is critical to the production and timing of shipments.

The Company's Rig Systems segment provides drilling rig components as well as complete land drilling rigs and offshore drilling equipment packages the primary manufacturing facilities are located in Houston, Galena Park, Sugar Landand Pampa, Texas; McAlester, Oklahoma; Orange, California; Edmonton, Canada; Kristiansand, Stavanger, Sogne, Oslo and Molde, Norway; Etten-Leur, the Netherlands; Carquefou, France; Mexicali, Mexico; Shanghai, China; and Ulsan, South Korea.

The Company's Rig Aftermarket segment provides comprehensive aftermarket products and services to support land rigs and offshore rigs, and drilling rig components manufactured by the Rig Systems segment. Primary facilities are located in Houston, Texas; Lafayette, and New Iberia, Louisiana; Aberdeen and Montrose, Scotland; Singapore; Dubai, UAE; Port Elizabeth and Cape Town, South Africa; Macae, Brazil and Luanda, Angola.

The Wellbore Technologies segment engineers, manufactures or assembles the equipment and products which it rents and sells to customers, and which it uses in providing services. Downhole manufactures at facilities in Houston and Conroe, Texas; Stonehouse and Manchester, U.K; Dubai, UAE; Macaé, Brazil and Singapore. Drill Pipe manufactures at facilities in Navasota, Texas; Veracruz, Mexico; Singapore; Jiangyan and Tianjin, China; Batam Island, Indonesia and Abu Dhabi, UAE. Tuboscope manufactures tubular inspection and coating products for internal use and for resale in Houston, Texas, it also renovates and repairs equipment at its manufacturing facilities in Houston, Celle, Germany and Buenos Aires, Argentina. Well Site Services manufactures the Brandt Solids Control product line in Conroe, Texas and Aberdeen, Scotland, and produces shale shaker screens for use in solids / fluid separation process in facilities located in Conroe; Kuala Lumpur, Malaysia; New Iberia, Louisiana; Leduc, Canada and Victoria, Brazil. IntelliServ buys drill pipe from Grant Prideco's Navasota, Texas facility and ships it to their facility in Provo, Utah where the coax cable is installed. IntelliServ's engineering team is located at the facility in Provo. Dynamic Drilling Solutions manufactures instrumentation and Etools from Cedar Park, Austin and Stafford, Texas and Andoversford, U.K.

The Completion & Productions Solutions segment integrates technologies for well completions and oil and gas production. Pumps and production process equipment are manufactured at facilities in Houston, Odessa and San Angelo, Tesas; Harvey, Louisiana; McAlester and Tulsa, Oklahoma; Manchester and Newcastle, England; Melbourne, Australia; Dubai, UAE: and Buenos Aires, Argentina. Fiberglass and composite tubulars and fittings are manufactured at facilities in Houston, San Antonio, Burkburnett and Mineral Wells, Texas; Little Rock, Arkansas; Tulsa, Oklahoma; Wichita, Kansas; Geldermalsen, the Netherlands; Betim, Brazil; Johor, Malaysia; Singapore and Harbin and Suzhou, China. NOV's well intervention and stimulation equipment business brings together some of the world's leading engineering and manufacturing divisions in the areas of coiled tubing, nitrogen pumping, snubbing, pressure control, fracturing, cementing, wireline, and associated engineering services. These products are manufactured in Anderson, Houston and Ft Worth Texas; Lafayette, Louisiana; Duncan, Oklahoma; Aberdeen, Newcastle, and Great Yarmouth, UK; Calgary, Canada; Dubai, UAE; Singapore; Perth, Australia; Minsk, Belarus; and Nievwpoort, NL; Flexible pipe for subsea applications is manufactured in Denmark and Brazil. Certain of the Company's manufacturing facilities and certain of the Company's products have various certifications, including, ISO 9001, API, APEX and ASME.

Raw Materials

The Company believes that materials and components used in its servicing and manufacturing operations and purchased for sales are generally available from multiple sources. The prices paid by the Company for its raw materials may be affected by, among other things, energy, steel and other commodity prices; tariffs and duties on imported materials; and foreign currency exchange rates. Since 2006 the Company has experienced rising, declining and stable prices for mild steel and standard grades in line with broader economic activity and has generally seen specialty alloy prices continued to rise, driven primarily by escalation in the price of the alloying agents. The Company has generally been successful in its effort to mitigate the financial impact of higher raw materials costs on its operations by applying surcharges to and adjusting prices on the products it sells. Furthermore, the Company continued to expand its supply base starting in 2006 throughout the world to address its customers' needs. In 2012 and 2013, the Company witnessed flat to slight increases in steel pricing which was somewhat mitigated by improved sourcing and supply chain practices. The Company anticipates flat to moderate increases in steel pricing in 2014. Higher prices and lower availability of steel and other raw materials the Company uses in its business may adversely impact future periods.

Backlog

The Company monitors its backlog of orders within its Rig Systems and Completion & Production Solutions segments to guide its planning. Backlog includes orders which typically require more than three months to manufacture and deliver.

Backlog measurements are made on the basis of written orders which are firm, but may be defaulted upon by the customer in some instances. Most require reimbursement to the Company for costs incurred in such an event. There can be no assurance that the backlog amounts will ultimately be realized as revenue, or that the Company will earn a profit on backlog work. Backlog for the Rig Systems segment at December 31, 2013, 2012 and 2011, was $15.0 billion, $10.9 billion and $9.2 billion, respectively. Backlog for the Completion & Production Solutions segment at December 31, 2013, 2012 and 2011 was $1.6 billion, $1.3 billion and $1.3 billion, respectively.

Employees

At December 31, 2013, the Company had a total of 58,078 employees, of which 8,195 were temporary employees. Approximately 1,167 employees in the U.S. are subject to collective bargaining agreements. Additionally, certain of the Company’s employees in various foreign locations are subject to collective bargaining agreements. The Company believes its relationship with its employees is good.

ITEM 1A. RISK FACTORS

You should carefully consider the risks described below, in addition to other information contained or incorporated by reference herein. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

We are dependent upon the level of activity in the oil and gas industry, which is volatile.

The oil and gas industry historically has experienced significant volatility. Demand for our services and products depends primarily upon the number of oil rigs in operation, the number of oil and gas wells being drilled, the depth and drilling conditions of these wells, the volume of production, the number of well completions, capital expenditures of other oilfield service companies and the level of workover activity. Drilling and workover activity can fluctuate significantly in a short period of time, particularly in the United States and Canada. The willingness of oil and gas operators to make capital expenditures to explore for and produce oil and natural gas and the willingness of oilfield service companies to invest in capital equipment will continue to be influenced by numerous factors over which we have no control, including:

- the ability of the members of the Organization of Petroleum Exporting Countries, or OPEC, to maintain price stability through voluntary production limits, the level of production by non-OPEC countries and worldwide demand for oil and gas;
- level of production from known reserves;
- cost of exploring for and producing oil and gas;
- level of drilling activity and drilling rig dayrates;
- worldwide economic activity;
- national government political requirements;
- development of alternate energy sources; and
- environmental regulations.

If there is a significant reduction in demand for drilling services, in cash flows of drilling contractors, well servicing companies, or production companies or in drilling or well servicing rig utilization rates, then demand for the products and services of the Company will decline.

Volatile oil and gas prices affect demand for our products.

Oil and gas prices have been volatile since 1972. In general, oil prices approximated $18-$22 per barrel from 1991 through 1997, experienced a decline into the low teens in 1998 and 1999, and have generally ranged between $25-$100 per barrel since 2000. In 2008, oil prices were extremely volatile – oil prices rose to $147 per barrel in July 2008 only to fall into the $35-$45 per barrel range in December 2008. Oil prices then recovered since 2009, and rose to $85 per barrel by the end of 2010. Oil prices remained flat in the $90—$100 per barrel range through 2012 and 2013. Domestic spot gas prices generally ranged between $1.80-$2.60 per mmbtu of gas from 1991 through 1999 then experienced spikes into the $10 range in 2001 and 2003. Prices generally ranged between $4.50-$12.00 per mmbtu during 2005-2008. During 2009 through 2011, spot gas prices generally stabilized, dropping into the $3.00—$4.50 per mmbtu range, but declined below $3.00 late in 2011 and throughout much of 2012 before increasing slightly above $3.00 in late 2012. During 2013, prices continued to rise and remained steady in the $3.00—$4.50 per mmbtu range ending the year over $4.00 per mmbtu.

Expectations for future oil and gas prices cause many shifts in the strategies and expenditure levels of oil and gas companies and drilling contractors, particularly with respect to decisions to purchase major capital equipment of the type we manufacture. Oil and gas prices, which are determined by the marketplace, may fall below a range that is acceptable to our customers, which could reduce demand for our products.

Worldwide financial and credit crisis could have a negative effect on our operating results and financial condition.

Events in 2008 and 2009 constrained credit markets and sparked a serious global banking crisis. The slowdown in worldwide economic activity caused by the global recession reduced demand for energy and resulted in lower oil and natural gas prices. Any prolonged reduction in oil and natural gas prices will reduce oil and natural gas drilling activity and result in a corresponding decline in the demand for our products and services, which could adversely impact our operating results and financial condition. Furthermore, many of our customers access the credit markets to finance their oil and natural gas drilling activity. If the recent crisis and recession reduce the availability of credit to our customers, they may reduce their drilling and production expenditures, thereby decreasing demand for our products and services. Any such reduction in spending by our customers could adversely impact our operating results and financial condition.

There are risks associated with certain contracts for our drilling equipment.

As of December 31, 2013, we had a backlog of capital equipment to be manufactured, assembled, tested and delivered by our Rig Systems and Completion & Production Solutions segments in the amount of $15.0 million and $1.6 million, respectively. The following factors, in addition to others not listed, could reduce our margins on these contracts, adversely affect our position in the market or subject us to contractual penalties:

- our failure to adequately estimate costs for making this drilling equipment;
- our inability to deliver equipment that meets contracted technical requirements;
- our inability to maintain our quality standards during the design and manufacturing process;
- our inability to secure parts made by third party vendors at reasonable costs and within required timeframes;
- unexpected increases in the costs of raw materials; and
- our inability to manage unexpected delays due to weather, shipyard access, labor shortages or other factors beyond our control.

The Company’s existing contracts for rig equipment generally carry significant down payment and progress billing terms favorable to the ultimate completion of these projects and the majority do not allow customers to cancel projects for convenience. However, unfavorable market conditions or financial difficulties experienced by our customers may result in cancellation of contracts or the delay or abandonment of projects.

Any such developments could have a material adverse effect on our operating results and financial condition.

Competition in our industry could ultimately lead to lower revenues and earnings.

The oilfield products and services industry is highly competitive. We compete with national, regional and foreign competitors in each of our current major product lines. Certain of these competitors may have greater financial, technical, manufacturing and marketing resources than us, and may be in a better competitive position. The following competitive actions can each affect our revenues and earnings:

- price changes;
- new product and technology introductions; and
- improvements in availability and delivery.

In addition, certain foreign jurisdictions and government-owned petroleum companies located in some of the countries in which we operate have adopted policies or regulations which may give local nationals in these countries competitive advantages. Competition in our industry could lead to lower revenues and earnings.

We have aggressively expanded our businesses and intend to maintain an aggressive growth strategy.

We have aggressively expanded and grown our businesses during the past several years, through acquisitions and investment in internal growth. We anticipate that we will continue to pursue an aggressive growth strategy but we cannot assure you that attractive acquisitions will be available to us at reasonable prices or at all. In addition, we cannot assure you that we will successfully integrate the operations and assets of any acquired business with our own or that our management will be able to manage effectively the increased size of the Company or operate any new lines of business. Any inability on the part of management to integrate and manage acquired businesses and their assumed liabilities could adversely affect our business and financial performance. In addition, we may need to incur substantial indebtedness to finance future acquisitions. We cannot assure you that we will be able to obtain this financing on terms acceptable to us or at all. Future acquisitions may result in increased depreciation and amortization expense, increased interest expense, increased financial leverage or decreased operating income for the Company, any of which could cause our business to suffer.

Our operating results have fluctuated during recent years and these fluctuations may continue.

We have experienced fluctuations in quarterly operating results in the past. We cannot assure that we will realize earnings growth or that earnings in any particular quarter will not fall short of either a prior fiscal quarter or investors' expectations. The following factors, in addition to others not listed, may affect our quarterly operating results in the future:

- fluctuations in the oil and gas industry;
- competition;
- the ability to service the debt obligations of the Company;
- the ability to identify strategic acquisitions at reasonable prices;
- the ability to manage and control operating costs of the Company;
- fluctuations in political and economic conditions in the United States and abroad; and
- the ability to protect our intellectual property rights.

There are risks associated with our presence in international markets, including political or economic instability, currency restrictions, and trade and economic sanctions.

Approximately 75% of our revenues in 2013 were derived from operations outside the United States (based on revenue destination). Our foreign operations include significant operations in Canada, Europe, the Middle East, Africa, Southeast Asia, Latin America and other international markets. Our revenues and operations are subject to the risks normally associated with conducting business in foreign countries, including uncertain political and economic environments, which may limit or disrupt markets, restrict the movement of funds or result in the deprivation of contract rights or the taking of property without fair compensation. Government-owned petroleum companies located in some of the countries in which we operate have adopted policies, or are subject to governmental policies, giving preference to the purchase of goods and services from companies that are majority-owned by local nationals. As a result of these policies, we may rely on joint ventures, license arrangements and other business combinations with local nationals in these countries. In addition, political considerations may disrupt the commercial relationships between us and government-owned petroleum companies.

Our operations outside the United States could also expose us to trade and economic sanctions or other restrictions imposed by the United States or other governments or organizations. The U.S. Department of Justice ("DOJ"), the U.S. Securities and Exchange Commission and other federal agencies and authorities have a broad range of civil and criminal penalties they may seek to impose against corporations and individuals for violations of trading sanctions laws, the Foreign Corrupt Practices Act and other federal statutes. Under trading sanctions laws, the DOJ may seek to impose modifications to business practices, including cessation of business activities in sanctioned countries, and modifications to compliance programs, which may increase compliance costs. If any of the risks described above materialize, it could adversely impact our operating results and financial condition.

We have received federal grand jury subpoenas and subsequent inquiries from governmental agencies requesting records related to our compliance with export trade laws and regulations. We have cooperated fully with agents from the Department of Justice, the Bureau of Industry and Security, the Office of Foreign Assets Control, and U.S. Immigration and Customs Enforcement in responding to the inquiries. We have also cooperated with an informal inquiry from the Securities and Exchange Commission in connection with the inquiries previously made by the aforementioned federal agencies. We have conducted our own internal review of this matter. At the conclusion of our internal review in the fourth quarter of 2009, we identified possible areas of concern and discussed these areas of concern with the relevant agencies. We are currently negotiating a potential resolution with the agencies involved related to these matters. We currently anticipate that any administrative fine or penalty agreed to as part of a resolution would be within established accruals, and would not have a material effect on our financial position or results of operations. To the extent a resolution is not negotiated as anticipated, we cannot predict the timing or effect that any resulting government actions may have on our financial position or results of operations.

The results of our operations are subject to market risk from changes in foreign currency exchange rates.

We earn revenues, pay expenses, purchase assets and incur liabilities in countries using currencies other than the U.S. dollar, including, but not limited to, the Canadian dollar, the Euro, the British pound sterling, the Norwegian krone and the South Korean won. Approximately 75% of our 2013 revenue was derived from sales outside the United States. Because our Consolidated Financial Statements are presented in U.S. dollars, we must translate revenues and expenses into U.S. dollars at exchange rates in effect during or at the end of each reporting period. Thus, increases or decreases in the value of the U.S. dollar against other currencies in which our operations are conducted will affect our revenues and operating income. Because of the geographic diversity of our operations, weaknesses in some currencies might be offset by strengths in others over time. We use derivative financial instruments to mitigate our net exposure to currency exchange fluctuations. We had forward contracts with a notional amount of $4,537 million (with a fair value of a net asset of $19 million) as of December 31, 2013, to reduce the impact of foreign currency exchange rate movements. We are also subject to risks that the counterparties to these contracts fail to meet the terms of our foreign currency contracts. We cannot assure you that fluctuations in foreign currency exchange rates would not affect our financial results.

An impairment of goodwill or other indefinite lived intangible assets could reduce our earnings.

The Company has approximately $9.0 billion of goodwill and $0.6 billion of other intangible assets with indefinite lives as of December 31, 2013, of which approximately $0.3 billion of goodwill relates to the distribution business we spun-off in May 2014. Generally accepted accounting principles require the Company to test goodwill and other indefinite lived intangible assets for impairment on an annual basis or whenever events or circumstances occur indicating that goodwill might be impaired. Events or circumstances which could indicate a potential impairment include (but are not limited to) a significant reduction in worldwide oil and gas prices or drilling; a significant reduction in profitability or cash flow of oil and gas companies or drilling contractors; a significant reduction in worldwide well remediation activity; a significant reduction in capital investment by other oilfield service companies; or a significant increase in worldwide inventories of oil or gas. The timing and magnitude of any goodwill impairment charge, which could be material, would depend on the timing and severity of the event or events triggering the charge and would require a high degree of management judgment. If we were to determine that any of our remaining balance of goodwill or other indefinite lived intangible assets was impaired, we would record an immediate charge to earnings with a corresponding reduction in stockholders' equity; resulting in an increase in balance sheet leverage as measured by debt to total capitalization.

See additional discussion on "Goodwill and Other Indefinite – Lived Intangible Assets" in Critical Accounting Estimates of Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

We could be adversely affected if we fail to comply with any of the numerous federal, state and local laws, regulations and policies that govern environmental protection, zoning and other matters applicable to our businesses.

Our businesses are subject to numerous federal, state and local laws, regulations and policies governing environmental protection, zoning and other matters. These laws and regulations have changed frequently in the past and it is reasonable to expect additional changes in the future. If existing regulatory requirements change, we may be required to make significant unanticipated capital and operating expenditures. We cannot assure you that our operations will continue to comply with future laws and regulations. Governmental authorities may seek to impose fines and penalties on us or to revoke or deny the issuance or renewal of operating permits for failure to comply with applicable laws and regulations. Under these circumstances, we might be required to reduce or cease operations or conduct site remediation or other corrective action which could adversely impact our operations and financial condition.

Our businesses expose us to potential environmental liability.

Our businesses expose us to the risk that harmful substances may escape into the environment, which could result in:

- personal injury or loss of life;
- severe damage to or destruction of property; or
- environmental damage and suspension of operations.

Our current and past activities, as well as the activities of our former divisions and subsidiaries, could result in our facing substantial environmental, regulatory and other liabilities. These could include the costs of cleanup of contaminated sites and site closure obligations. These liabilities could also be imposed on the basis of one or more of the following theories:

- negligence;
- strict liability;
- breach of contract with customers; or
- as a result of our contractual agreement to indemnify our customers in the normal course of business, which is normally the case.

We may not have adequate insurance for potential environmental liabilities.

While we maintain liability insurance, this insurance is subject to coverage limits. In addition, certain policies do not provide coverage for damages resulting from environmental contamination. We face the following risks 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.

Even a partially uninsured claim, if successful and of significant size, could have a material adverse effect on our consolidated financial statements.

The adoption of climate change legislation or regulations restricting emissions of greenhouse gases could increase our operating costs or reduce demand for our products.

Environmental advocacy groups and regulatory agencies in the United States and other countries have been focusing considerable attention on the emissions of carbon dioxide, methane and other greenhouse gases and their potential role in climate change. The adoption of laws and regulations to implement controls of greenhouse gases, including the imposition of fees or taxes, could adversely impact our operations and financial condition. The U.S. Congress is currently working on legislation to control and reduce emissions of greenhouse gases in the United States, which includes establishing cap-and-trade programs. In addition to the pending climate legislation, the U.S. Environmental Protection Agency has proposed regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities, and may issue final rules this year. These changes in the legal and regulatory environment could reduce oil and natural gas drilling activity and result in a corresponding decline in the demand for our products and services, which could adversely impact our operating results and financial condition.

We had revenues of greater than 10% of total revenue from one of our customers during the years ended December 31, 2013, 2012 and 2011.

The loss of this customer (Samsung Heavy Industries) or a significant reduction in its purchases could adversely affect our future revenues and earnings. Samsung Heavy Industries is a shipyard acting as a general contractor for its customers, who are drillship owners and drilling contractors. This shipyard’s customers have specified that the Company’s drilling equipment be installed on their drillships and have required the shipyard to issue contracts to the Company.

Our information systems may experience an interruption or breach in security.

We rely heavily on information systems to conduct our business. Any failure, interruption or breach in security of our information systems could result in failures or disruptions in our customer relationship management, general ledger systems and other systems. While we have policies and procedures designed to prevent or limit the effect of the failure, interruption or security breach of our information systems, there can be no assurance that any such failures, interruptions or security breaches will not occur or, if they do occur, that they will be adequately addressed. The occurrence of any failures, interruptions or security breaches of the our information systems could damage our reputation, result in a loss of customer business, subject us to additional regulatory scrutiny, or expose us to civil litigation and possible financial liability, any of which could have a material adverse effect on our financial position or results of operations.

Risks associated with the separation of our distribution business.

Our separation of our distribution business is subject to a number of risks, including the following:

Risks of Not Obtaining Benefits from the Separation. NOV and NOW Inc. may not realize some or all of the benefits we expect from the separation in the time frame currently contemplated, or at all.

Risks Relating to Less Diversification. Our diversification of revenue sources will diminish due to the separation of NOW Inc. from our other businesses, and it is possible that our results of operations, cash flows, working capital and financing requirements may be subject to increased volatility as a result.

Risks Relating to Taxes. The IRS no longer issues private letter rulings regarding whether or not a spin-off transaction qualifies for tax-free treatment under Section 355 of the Code. Notwithstanding the tax opinions we are to receive from our legal and tax advisors that the distribution of 100% of the shares of NOW Inc. common stock will qualify as tax-free under such section of the Code, the IRS could determine on audit that the distribution should be treated as a taxable transaction, including as a result of a significant change in stock or asset ownership after the distribution. If the distribution ultimately is determined to be taxable, we and/or our stockholders that are subject to U.S. federal income tax could incur significant U.S. federal income tax liabilities.

	(Sources: Company management; "A Dictionary for the Petroleum Industry," The University of Texas at Austin, 2001.)
API	Abbr: American Petroleum Institute
Annular Blowout Preventer	A large valve, usually installed above the ram blowout preventers, that forms a seal in the annular space between the pipe and the wellbore or, if no pipe is present, in the wellbore itself.
Annulus	The open space around pipe in a wellbore through which fluids may pass.
Automatic Pipe Handling Systems (Automatic Pipe Racker)	A device used on a drilling rig to automatically remove and insert drill stem components from and into the hole. It replaces the need for a person to be in the derrick or mast when tripping pipe into or out of the hole.
Automatic Roughneck	A large, self-contained pipe-handling machine used by drilling crew members to make up and break out tubulars. The device combines a spinning wrench, torque wrench, and backup wrenches.
Beam pump	Surface pump that raise and lowers sucker rods continually, so as to operate a downhole pump.
Bit	The cutting or boring element used in drilling oil and gas wells. The bit consists of a cutting element and a circulating element. The cutting element is steel teeth, tungsten carbide buttons, industrial diamonds, or polycrystalline diamonds ("PDCs"). These teeth, buttons, or diamonds penetrate and gouge or scrape the formation to remove it. The circulating element permits the passage of drilling fluid and utilizes the hydraulic force of the fluid stream to improve drilling rates. In rotary drilling, several drill collars are joined to the bottom end of the drill pipe column, and the bit is attached to the end of the drill collars. Drill collars provide weight on the bit to keep it in firm contact with the bottom of the hole. Most bits used in rotary drilling are roller cone bits, but diamond bits are also used extensively.
Blowout	An uncontrolled flow of gas, oil or other well fluids into the atmosphere. A blowout, or gusher, occurs when formation pressure exceeds the pressure applied to it by the column of drilling fluid. A kick warns of an impending blowout.
Blowout Preventer (BOP)	Series of valves installed at the wellhead while drilling to prevent the escape of pressurized fluids.
Blowout Preventer (BOP) Stack	The assembly of well-control equipment including preventers, spools, valves, and nipples connected to the top of the wellhead.
Closed Loop Drilling Systems	A solids control system in which the drilling mud is reconditioned and recycled through the drilling process on the rig itself.
Coiled Tubing	A continuous string of flexible steel tubing, often hundreds or thousands of feet long, that is wound onto a reel, often dozens of feet in diameter. The reel is an integral part of the coiled tubing unit, which consists of several devices that ensure the tubing can be safely and efficiently inserted into the well from the surface. Because tubing can be lowered into a well without having to make up joints of tubing, running coiled tubing into the well is faster and less expensive than running conventional tubing. Rapid advances in the use of coiled tubing make it a popular way in which to run tubing into and out of a well. Also called reeled tubing.
Cuttings	Fragments of rock dislodged by the bit and brought to the surface in the drilling mud. Washed and dried cutting samples are analyzed by geologist to obtain information about the formations drilled.
Directional Well	Well drilled in an orientation other than vertical in order to access broader portions of the formation.
Drawworks	The hoisting mechanism on a drilling rig. It is essentially a large winch that spools off or takes in the drilling line and thus raises or lowers the drill stem and bit.

Drill Pipe Elevator (Elevator)	On conventional rotary rigs and top-drive rigs, hinged steel devices with manual operating handles that crew members latch onto a tool joint (or a sub). Since the elevators are directly connected to the traveling block, or to the integrated traveling block in the top drive, when the driller raises or lowers the block or the top-drive unit, the drill pipe is also raised or lowered.
Drilling jars	A percussion tool operated manually or hydraulically to deliver a heavy downward blow to free a stuck drill stem.
Drilling mud	A specially compounded liquid circulated through the wellbore during rotary drilling operations.
Drilling riser	A conduit used in offshore drilling through which the drill bit and other tools are passed from the rig on the water’s surface to the sea floor.
Drill stem	All members in the assembly used for rotary drilling from the swivel to the bit, including the Kelly, the drill pipe and tool joints, the drill collars, the stabilizers, and various specialty items.
Fiberglass-reinforced spoolable pipe	A spoolable glass fiber-reinforced epoxy composite tubular product for onshore oil and gas gathering and injection systems, with superior corrosion resistant properties and lower installed cost than steel.
Flexible pipe	A dynamic riser that connects subsea production equipment to a topside facility allowing for the flow of oil, gas, and/or water.
Formation	A bed or deposit composed throughout of substantially the same kind of rock; often a lithologic unit. Each formation is given a name, frequently as a result of the study of the formation outcrop at the surface and sometimes based on fossils found in the formation.
FPSO	A Floating Production, Storage and Offloading vessel used to receive hydrocarbons from subsea wells, and then produce and store the hydrocarbons until they can be offloaded to a tanker or pipeline.
Hardbanding	A special wear-resistant material often applied to tool joints to prevent abrasive wear to the area when the pipe is being rotated downhole.
Hydraulic Fracturing	The process of creating fractures in a formation by pumping fluids, at high pressures, into the reservoir, which allows or enhances the flow of hydrocarbons.
Iron Roughneck	A floor-mounted combination of a spinning wrench and a torque wrench. The Iron Roughneck moves into position hydraulically and eliminates the manual handling involved with suspended individual tools.
Jack-up rig	A mobile bottom-supported offshore drilling structure with columnar or open-truss legs that support the deck and hull. When positioned over the drilling site, the bottoms of the legs penetrate the seafloor.
Jar	A mechanical device placed near the top of the drill stem which allows the driller to strike a very heavy blow upward or downward on stuck pipe.
Joint	1. In drilling, a single length (from 16 feet to 45 feet, or 5 meters to 14.5 meters, depending on its range length) of drill pipe, drill collar, casing or tubing that has threaded connections at both ends. Several joints screwed together constitute a stand of pipe. 2. In pipelining, a single length (usually 40 feet-12 meters) of pipe. 3. In sucker rod pumping, a single length of sucker rod that has threaded connections at both ends.

Kelly	The heavy steel tubular device, four- or six-sided, suspended from the swivel through the rotary table and connected to the top joint of drill pipe to turn the drill stem as the rotary table returns. It has a bored passageway that permits fluid to be circulated into the drill stem and up the annulus, or vice versa. Kellys manufactured to API specifications are available only in four- or six-sided versions, are either 40 or 54 feet (12 to 16 meters) long, and have diameters as small as 2.5 inches (6 centimeters) and as large as 6 inches (15 centimeters).
Kelly bushing	A special device placed around the kelly that mates with the kelly flats and fits into the master bushing of the rotary table. The kelly bushing is designed so that the kelly is free to move up or down through it. The bottom of the bushing may be shaped to fit the opening in the master bushing or it may have pins that fit into the master bushing. In either case, when the kelly bushing is inserted into the master bushing and the master bushing is turned, the kelly bushing also turns. Since the kelly bushing fits onto the kelly, the kelly turns, and since the kelly is made up to the drill stem, the drill stem turns. Also called the drive bushing.
Kelly spinner	A pneumatically operated device mounted on top of the kelly that, when actuated, causes the kelly to turn or spin. It is useful when the kelly or a joint of pipe attached to it must be spun up, that is, rotated rapidly for being made up.
Kick	An entry of water, gas, oil, or other formation fluid into the wellbore during drilling. It occurs because the pressure exerted by the column of drilling fluid is not great enough to overcome the pressure exerted by the fluids in the formation drilled. If prompt action is not taken to control the kick, or kill the well, a blowout may occur.
Making-up	1. To assemble and join parts to form a complete unit (e.g., to make up a string of drill pipe). 2. To screw together two threaded pieces. Compare break out. 3. To mix or prepare (e.g., to make up a tank of mud). 4. To compensate for (e.g., to make up for lost time).
Manual tongs (Tongs)	The large wrenches used for turning when making up or breaking out drill pipe, casing, tubing, or other pipe; variously called casing tongs, pipe tongs, and so forth, according to the specific use. Power tongs or power wrenches are pneumatically or hydraulically operated tools that serve to spin the pipe up tight and, in some instances to apply the final makeup torque.
Master bushing	A device that fits into the rotary table to accommodate the slips and drive the kelly bushing so that the rotating motion of the rotary table can be transmitted to the kelly. Also called rotary bushing.
Mooring system	The method by which a vessel or buoy is fixed to a certain position, whether permanently or temporarily.
Motion compensation equipment	Any device (such as a bumper sub or heave compensator) that serves to maintain constant weight on the bit in spite of vertical motion of a floating offshore drilling rig.
Mud pump	A large, high-pressure reciprocating pump used to circulate the mud on a drilling rig.
Plug gauging	The mechanical process of ensuring that the inside threads on a piece of drill pipe comply with API standards.
Pressure control equipment	Equipment used in: 1. The act of preventing the entry of formation fluids into a wellbore. 2. The act of controlling high pressures encountered in a well.
Pressure pumping	Pumping fluids into a well by applying pressure at the surface.
Ram blowout preventer	A blowout preventer that uses rams to seal off pressure on a hole that is with or without pipe. Also called a ram preventer.
Ring gauging	The mechanical process of ensuring that the outside threads on a piece of drill pipe comply with API standards.
Riser	A pipe through which liquids travel upward.

Riser pipe	The pipe and special fitting used on floating offshore drilling rigs to established a seal between the top of the wellbore, which is on the ocean floor, and the drilling equipment located above the surface of the water. A riser pipe serves as a guide for the drill stem from the drilling vessel to the wellhead and as a conductor or drilling fluid from the well to the vessel. The riser consists of several sections of pipe and includes special devices to compensate for any movement of the drilling rig caused by waves. Also called marine riser pipe, riser joint.
Rotary table	The principal piece of equipment in the rotary table assembly; a turning device used to impart rotational power to the drill stem while permitting vertical movement of the pipe for rotary drilling. The master bushing fits inside the opening of the rotary table; it turns the kelly bushing, which permits vertical movement of the kelly while the stem is turning.
Rotating blowout preventer (Rotating Head)	A sealing device used to close off the annular space around the kelly in drilling with pressure at the surface, usually installed above the main blowout preventers. A rotating head makes it possible to drill ahead even when there is pressure in the annulus that the weight of the drilling fluid is not overcoming; the head prevents the well from blowing out. It is used mainly in the drilling of formations that have low permeability. The rate of penetration through such formations is usually rapid.
Safety clamps	A clamp placed very tightly around a drill collar that is suspended in the rotary table by drill collar slips. Should the slips fail, the clamp is too large to go through the opening in the rotary table and therefore prevents the drill collar string from falling into the hole. Also called drill collar clamp.
Shaker	See “Shale Shaker”
Shale shaker	A piece of drilling rig equipment that uses a vibrating screen to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the screen should be selected carefully to be the smallest size possible to allow 100 per cent flow of the fluid. Also called a shaker.
Slim-hole completions (Slim-hole Drilling)	Drilling in which the size of the hole is smaller than the conventional hole diameter for a given depth. This decrease in hole size enables the operator to run smaller casing, thereby lessening the cost of completion.
Slips	Wedge-shaped pieces of metal with serrated inserts (dies) or other gripping elements, such as serrated buttons, that suspend the drill pipe or drill collars in the master bushing of the rotary table when it is necessary to disconnect the drill stem from the kelly or from the top-drive unit’s drive shaft. Rotary slips fit around the drill pipe and wedge against the master bushing to support the pipe. Drill collar slips fit around a drill collar and wedge against the master bushing to support the drill collar. Power slips are pneumatically or hydraulically actuated devices that allow the crew to dispense with the manual handling of slips when making a connection.
Solids	See “Cuttings”
Spinning wrench	Air-powered or hydraulically powered wrench used to spin drill pipe in making or breaking connections.
Spinning-in	The rapid turning of the drill stem when one length of pipe is being joined to another. “Spinning-out” refers to separating the pipe.
Stand	The connected joints of pipe racked in the derrick or mast when making a trip. On a rig, the usual stand is about 90 feet (about 27 meters) long (three lengths of drill pipe screwed together), or a treble.
String	The entire length of casing, tubing, sucker rods, or drill pipe run into a hole.
Sucker rod	A special steel pumping rod. Several rods screwed together make up the link between the pumping unit on the surface and the pump at the bottom of the well.

Tensioner	A system of devices installed on a floating offshore drilling rig to maintain a constant tension on the riser pipe, despite any vertical motion made by the rig. The guidelines must also be tensioned, so a separate tensioner system is provided for them.
Thermal desorption	The process of removing drilling mud from cuttings by applying heat directly to drill cuttings.
Tiebacks (Subsea)	A series of flowlines and pipes that connect numerous subsea wellheads to a single collection point.
Top drive	A device similar to a power swivel that is used in place of the rotary table to turn the drill stem. It also includes power tongs. Modern top drives combine the elevator, the tongs, the swivel, and the hook. Even though the rotary table assembly is not used to rotate the drill stem and bit, the top-drive system retains it to provide a place to set the slips to suspend the drill stem when drilling stops.
Torque wrench	Spinning wrench with a gauge for measuring the amount of torque being applied to the connection.
Trouble cost	Costs incurred as a result of unanticipated complications while drilling a well. These costs are often referred to as contingency costs during the planning phase of a well.
Turret	Mechanical device that allows a floating vessel to rotate around stationary flowlines, umbilicals, and other associated risers.
Well completion	1. The activities and methods of preparing a well for the production of oil and gas or for other purposes, such as injection; the method by which one or more flow paths for hydrocarbons are established between the reservoir and the surface. 2. The system of tubulars, packers, and other tools installed beneath the wellhead in the production casing; that is, the tool assembly that provides the hydrocarbon flow path or paths.
Wellhead	The termination point of a wellbore at surface level or subsea, often incorporating various valves and control instruments.
Well stimulation	Any of several operations used to increase the production of a well, such as acidizing or fracturing.
Well workover	The performance of one or more of a variety of remedial operations on a producing oil well to try to increase production. Examples of workover jobs are deepening, plugging back, pulling and resetting liners, and squeeze cementing.
Wellbore	A borehole; the hole drilled by the bit. A wellbore may have casing in it or it may be open (uncased); or part of it may be cased, and part of it may be open. Also called a borehole or hole.
Wireline	A slender, rodlike or threadlike piece of metal usually small in diameter, that is used for lowering special tools (such as logging sondes, perforating guns, and so forth) into the well. Also called slick line.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The Company owned or leased over 880 facilities worldwide as of December 31, 2013, including the following principal manufacturing, service, distribution and administrative facilities:

Location	Description	Building Size (SqFt)	Property Size (Acres)	Owned / Leased	Lease Termination Date
Rig Systems:					
Pampa, Texas	Manufacturing Plant	549,095	500	Owned	
Houston, Texas	Manufacturing Plant of Drilling Equipment	511,964	33	Leased	4/30/2019
Houston, Texas	West Little York Manufacturing Facility, Repairs, Service, Administrative & Sales Offices	483,450	34	Owned	
Ulsan, South Korea	Fabrication of Drilling Equipment	380,068	51	Owned	
Orange, California	Manufacturing & Office Facility	351,418	9	Owned*	12/31/2020
Houston, Texas	Manufacturing, Service, Warehouse & Administrative Offices (WGB)	245,319	14	Leased	3/31/2018
Sugar Land, Texas	Manufacturing Plant, Warehouse & Administrative Offices	223,345	24	Owned	
Carquefou, France	Manufacturing Plant of Offshore Equipment	213,000		Owned	
Galena Park, Texas	Manufacturing Plant (Drilling Rigs & Components) & Administrative Offices	191,913	22	Owned	
Houston, Texas	Manufacturing Plant of Drilling Rigs & Components, Admin & Sales Offices	170,040	11	Owned	
Kristiansand, Norway	Warehouse & Administrative/Sales Offices	167,200	1	Owned	
McAlester, Oklahoma	Manufacturing Facility of Pumps, Service & Administrative Offices	139,359	25	Owned	
Houston, Texas	Administrative Offices (Westchase)	125,494	4	Leased	9/30/2020
Molde, Norway	Manufacturing Facility of Drilling Equipment	78,000	1	Owned	
Etten Leur, Netherlands	Manufacturing Plant & Sales Offices (Drilling Equipment)	75,000	6	Owned	
Sogne, Norway	Warehouse and Offices	70,959	4	Leased	12/31/2017
Edmonton, Canada	Manufacturing Plant (Drilling Machinery & Equipment)	70,346	18	Owned	
Stavanger, Norway	Manufacturing Facility of Drilling Equipment	41,333	1	Leased	9/30/2015
Rig Aftermarket:					
Houston, Texas	Bammel Facility, Repairs, Service, Parts, Administrative & Sales Offices	377,750	19	Leased	6/30/2022
Lafayette, Louisiana	Repair, Services and Spares facility	189,000	17	Leased	9/28/2025
Aberdeen, Scotland	Pressure Control Manufacturing, Administrative & Sales Offices	188,200	5	Leased	8/31/2018
Singapore	Manufacturing, Repairs, Service, Field Service/Training, Administrative & Sales Offices	149,605	3	Leased	1/5/2024
Dubai, UAE	Repair & Overhaul of Drilling Equipment, Warehouse & Sales Office	31,633	2	Owned	
New Iberia, Louisiana	Riser Repair Facility	10,000	2	Leased	M-T-M

Location	Description	Building Size (SqFt)	Property Size (Acres)	Owned / Leased	Lease Termination Date
Wellbore Technologies:					
Navasota, Texas	Manufacturing Facility & Administrative Offices	562,112	196	Owned	
Conroe, Texas	Manufacturing Facility of Drill Bits and Downhole Tools, Administrative & Sales Offices	341,800	35	Owned	
Houston, Texas	Sheldon Road Inspection Facility	319,365	192	Owned	
Veracruz, Mexico	Manufacturing Facility of Tool Joints, Warehouse & Administrative Offices	303,400	42	Owned	
Houston, Texas	Holmes Rd Complex: Manufacturing, Warehouse, Coating Manufacturing Plant & Corporate Offices	300,000	50	Owned	
Cedar Park, Texas	Instrumentation Manufacturing Facility, Administrative & Sales Offices	215,778	40	Owned	
Dubai, UAE	Manufacturing Facility of Downhole Tools, Distribution Warehouse	180,000	1	Leased	1/29/2021
Conroe, Texas	Solids Control Manufacturing Facility, Warehouse, Administrative & Sales Offices, and Engineering Labs	153,750	35	Owned	
Bogota, Colombia	APCI Fabrication, Coating, Machine shop	146,904	33	Owned	
Singapore	Manufacturing Plant of Roller Cone Drill Bits, Shop, Warehouse & Administrative Offices	109,663	5	Leased	4/29/2048
Provo, Utah	Manufacturing Facility of Drilling Products, Fabrication, Warehouse & Administrative Offices	109,026	15	Owned	
Aberdeenshire, Scotland	Solids Control Manufacturing Facility, Assembly, Administrative & Sales Offices	107,250	6	Owned	
Larose, Louisiana	Generator Rentals & Service, Assembly, Warehouse & Administrative Offices	72,993	11	Leased	6/30/2016
Stonehouse, U.K.	Manufacturing Facility, Inspection Plant & Premium Threading Shop	71,000	4	Owned	
Dubai, UAE	Service Facility of Solids Control Equipment, Screens & Spare Parts, Inventory Warehouse, Sales, Rentals & Administrative Offices	14,569	1	Leased	10/31/2014
Rio de Janeiro, Brazil	Service and Repair Center, and Distribution Operations	12,116	1	Leased	M-T-M
Completion & Production Solutions:					
Schwetzingen, Baden-Wurttemberg, Germany	Manufacturing Facility of Glass Lined Reactor Vessels	729,890	17	Owned	
Senai, Malaysia	Manufacturing Facility of Fiber Glass Products	595,965	14	Owned*	
Kalundborg, Denmark	Flexibles Manufacturing, Warehouse, Shop & Administrative Offices	485,067	38	Owned*	
Little Rock, Arkansas	Manufacturing Facility of Fiber Glass Products	271,924	44	Owned	
Springfield, Ohio	Manufacturing Facility of PC Pumps	248,873	12	Owned	
Manchester, England	Manufacturing, Assembly & Testing of PC Pumps and Expendable Parts, Administrative & Sales Offices	244,000	11	Owned	
Houston, Texas	QT Coiled Tubing Manufacturing Facility, Warehouse & Offices	238,428	26	Owned	
Fort Worth, Texas	Coiled Tubing Manufacturing Facility, Warehouse, Administrative & Sales Offices	233,173	24	Owned	
Tulsa, Oklahoma	Manufacturing Facility of Pumps, Warehouse and Administrative & Sales Offices	212,625	10	Owned	

Location	Description	Building Size (SqFt)	Property Size (Acres)	Owned Leased	Lease Termination Date
Completion & Production Solutions:					
Durham, England	Manufacturing Facility, Warehouse & Administrative Offices	183,100	13	Leased	3/30/2066
Willis, Texas	R&M Manufacturing Facility of Drilling Motors	180,000	32	Owned	
Conroe, Texas	Manufacturing Plant, Administrative & Sales Offices	173,800	13	Leased	1/7/2022
Tracy, California	Water Transmission Group / Northern California	164,735	83	Owned	
Calgary, Canada	Manufacturing Facility & Administrative Offices	161,321	19	Leased	5/10/2017
Houston, Texas	Manufacturing of fiber-reinforced tubular products & Administrative Offices	146,668	6	Leased	6/30/2016
Anderson, Texas	Rolligon Manufacturing Facility, Administrative & Sales Offices	145,727	77	Leased	5/10/2016
Rancho Cucamonga, California	Water Transmission Group / Southern California	130,600	73	Owned	
Anniston, Alabama	Pole Products Manufacture	121,696	20	Leased	1/31/2015
San Antonio, Texas	Manufacturing Facility of Fiber Glass Products	120,084	20	Owned	
Edmonton, Canada	Manufacturing Facility, Repairs, Assembly, Warehouse & Administrative Offices	112,465	11	Owned	
Betim, Brazil	Manufacturing Facility of Fiber Glass Products	96,691	18	Owned	
Mineral Wells, Texas	Manufacturing Facility of Fiber Glass Products	95,640	15	Owned	
Duncan, Oklahoma	Nitrogen Units Manufacturing Facility, Warehouse & Offices	93,800	14	Owned	
Singapore	Manufacturing Facility of Fiber Glass Products	86,941	2	Leased	10/31/2015
Groot-Ammers, Netherlands	Workshop, Warehouse & Offices	61,859	3	Leased	12/31/2018
Kailua, Hawaii	KAAPA Quarry	53,980	163	Owned*	12/31/2052
Beaumont, Texas	Pipe Threading Facility, Fabrication, Warehouse & Administrative Offices	42,786	47	Owned	
Estevan, Canada	Distribution & Warehouse	27,842	6	Owned	
Honolulu, Hawaii	Hawaii Concrete Division Head Quarters	21,215	3	Leased	12/31/2027
Corporate:					
Houston, Texas	Corporate and Shared Administrative Offices	337,019	14	Leased	5/31/2017

* Building owned but land leased.

We own or lease approximately 185 repair and manufacturing facilities that refurbish and manufacture new equipment and parts, 95 distribution service centers and 600 service centers that provide inspection and equipment rental worldwide.

ITEM 3. LEGAL PROCEEDINGS

We have various claims, lawsuits and administrative proceedings that are pending or threatened, all arising in the ordinary course of business, with respect to commercial, product liability and employee matters. Although no assurance can be given with respect to the outcome of these or any other pending legal and administrative proceedings and the effect such outcomes may have, we believe any ultimate liability resulting from the outcome of such claims, lawsuits or administrative proceedings will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. See Note 12 to the Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Information regarding mine safety and other regulatory actions at our mines is included in Exhibit 95 to this Form 10-K.

PART II

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

Market Information

Our common stock is traded on the New York Stock Exchange (NYSE) under the symbol "NOV". The following table sets forth, for the calendar periods indicated, the range of high and low closing prices for the common stock, as reported by the NYSE and the cash dividends declared per share.

	2013				2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Common stock sale price:								
High	$74.14	$71.57	$79.83	$84.30	$87.18	$80.67	$84.83	$82.03
Low	$66.26	$64.14	$69.40	$77.77	$70.75	$60.00	$64.40	$64.87
Cash dividends per share	$ 0.13	$ 0.26	$ 0.26	$ 0.26	$ 0.12	$ 0.12	$ 0.12	$ 0.13

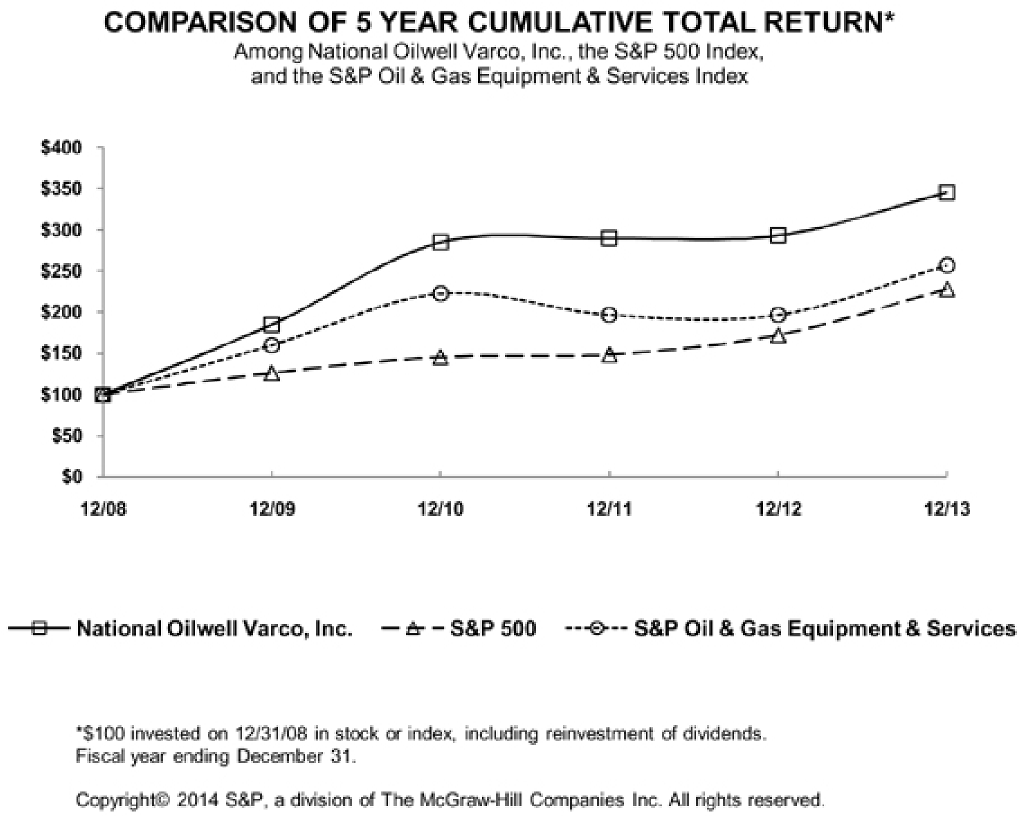
As of February 7, 2014, there were 3,106 holders of record of our common stock. Many stockholders choose to own shares through brokerage accounts and other intermediaries rather than as holders of (excluding individual participants in securities positions listing) record so the actual number of stockholders is unknown but significantly higher.

Cash dividends aggregated $389 million and $209 million for the years ended December 31, 2013 and 2012, respectively. The declaration and payment of future dividends is at the discretion of the Company's Board of Directors and will be dependent upon the Company's results of operations, financial condition, capital requirements and other factors deemed relevant by the Company's Board of Directors.

The information relating to our equity compensation plans required by Item 5. "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" is incorporated by reference to such information as set forth in Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" contained herein.

PERFORMANCE GRAPH

The graph below compares the cumulative total shareholder return on our common stock to the S&P 500 Index and the S&P Oil & Gas Equipment & Services Index. The total shareholder return assumes $100 invested on December 31, 2008 in National Oilwell Varco, Inc., the S&P 500 Index and the S&P Oil & Gas Equipment & Services Index. It also assumes reinvestment of all dividends. The peer group is weighted based on the market capitalization of each company. The results shown in the graph below are not necessarily indicative of future performance.



	12/08	12/09	12/10	12/11	12/12	12/13
National Oilwell Varco, Inc.	**$100.00**	**$185.01**	**$284.87**	**$289.82**	**$293.29**	**$345.43**
S&P 500	**100.00**	**126.46**	**145.51**	**148.59**	**172.37**	**228.19**
S&P Oil & Gas Equipment & Services	**100.00**	**159.79**	**222.56**	**196.56**	**196.57**	**256.81**

This information shall not be deemed to be ‘‘soliciting material’’ or to be ‘‘filed’’ with the Commission or subject to Regulation 14A (17 CFR 240.14a-1-240.14a-104), other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of section 18 of the Exchange Act (15 U.S.C. 78r).

ITEM 6. SELECTED FINANCIAL DATA

	Years Ended December 31,				
	2013 (1)	2012 (2)	2011	2010	2009
	(in millions, except per share data)				
Operating Data:					
Revenue	$19,221	$17,194	$13,475	$11,101	$11,795
Operating profit	3,199	3,389	2,809	2,363	2,264
Income from continuing operations before income taxes	3,124	3,340	2,794	2,319	2,163
Income from continuing operations	2,181	2,375	1,900	1,609	1,444
Income from discontinued operations	147	108	85	50	29
Net income attributable to Company	$ 2,327	$ 2,491	$ 1,994	$ 1,667	$ 1,469
Per share data:					
Basic:					
Income from continuing operations	$ 5.11	$ 5.61	$ 4.52	$ 3.85	$ 3.47
Income from discontinued operations	$ 0.35	$ 0.25	$ 0.21	$ 0.14	$ 0.06
Net income attributable to Company	$ 5.46	$ 5.86	$ 4.73	$ 3.99	$ 3.53
Diluted:					
Income from continuing operations	$ 5.09	$ 5.58	$ 4.50	$ 3.84	$ 3.46
Income from discontinued operations	$ 0.35	$ 0.25	$ 0.20	$ 0.14	$ 0.06
Net income attributable to Company	$ 5.44	$ 5.83	$ 4.70	$ 3.98	$ 3.52
Cash dividends per share	$ 0.91	$ 0.49	$ 0.45	$ 0.41	$ 1.10
Other Data:					
Depreciation and amortization	$ 738	$ 616	$ 549	$ 503	$ 484
Capital expenditures	$ 614	$ 569	$ 479	$ 231	$ 249
Balance Sheet Data:					
Working capital	$ 9,745	$10,029	$ 6,694	$ 5,999	$ 5,084
Total assets	$34,812	$31,484	$25,515	$23,050	$21,532
Long-term debt, less current maturities	$ 3,149	$ 3,148	$ 159	$ 514	$ 876
Total Company stockholders' equity	$22,230	$20,239	$17,619	$15,748	$14,113

(1) Financial information for prior periods and dates may not be comparable due to the impact of $2.4 billion in business combinations on our financial position and results of operations during 2013.

(2) Financial information for prior periods and dates may not be comparable due to the impact of $2.9 billion in business combinations on our financial position and results of operations during 2012.

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

General Overview

The Company is a leading worldwide provider of highly engineered drilling and well-servicing equipment, products and services to the exploration and production segments of the oil and gas industry. With operations in over 880 locations across six continents, we design, manufacture and service a comprehensive line of drilling and well servicing equipment; sell and rent drilling motors, specialized downhole tools, and rig instrumentation; perform inspection and internal coating of oilfield tubular products; provide drill cuttings separation, management and disposal systems and services; and provide expendables and spare parts used in conjunction with our large installed base of equipment. We also manufacture coiled tubing, manufacture high pressure fiberglass and composite tubing, and sell and rent advanced in-line inspection equipment to makers of oil country tubular goods. We have a long tradition of pioneering innovations which improve the cost-effectiveness, efficiency, safety, and environmental impact of oil and gas operations.

Our revenues and operating results are directly related to the level of worldwide oil and gas drilling and production activities and the profitability and cash flow of oil and gas companies and drilling contractors, which in turn are affected by current and anticipated prices of oil and gas. Oil and gas prices have been and are likely to continue to be volatile. See "Risk Factors". We conduct our operations through four business segments: Rig Systems, Rig Aftermarket, Wellbore Technologies and Completion & Production Solutions. See Item 1. "Business" for a discussion of each of these business segments.

Unless indicated otherwise, results of operations data are presented in accordance with accounting principles generally accepted in the United States ("GAAP"). In an effort to provide investors with additional information regarding our results of operations, certain non-GAAP financial measures, including operating profit excluding nonrecurring items, operating profit percentage excluding nonrecurring items and diluted earnings per share excluding nonrecurring items, are provided. See "Non-GAAP Financial Measures and Reconciliations" in Results of Operations for an explanation of our use of non-GAAP financial measures and reconciliations to their corresponding measures calculated in accordance with GAAP.

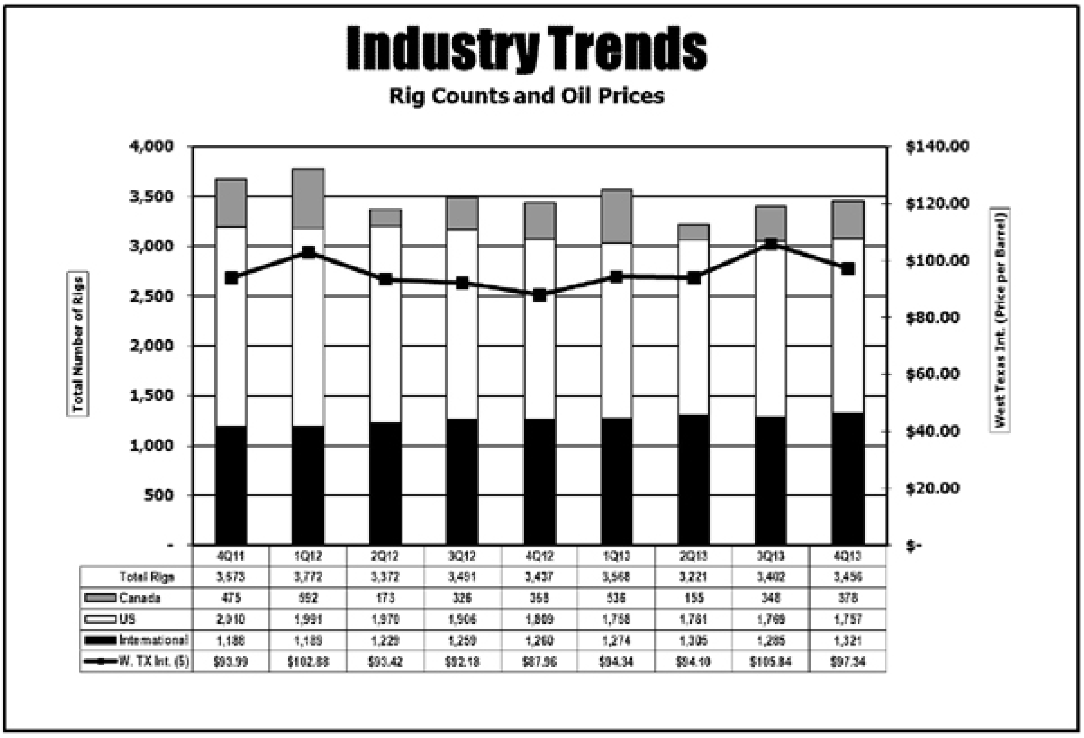
Operating Environment Overview

Our results are dependent on, among other things, the level of worldwide oil and gas drilling, well remediation activity, the price of crude oil and natural gas, capital spending by other oilfield service companies and drilling contractors, and the worldwide oil and gas inventory levels. Key industry indicators for the past three years include the following:

	2013*	2012*	2011*	% 2013 v 2012	% 2013 v 2011
Active Drilling Rigs:					
U.S.	1,761	1,919	1,875	(8.2%)	(6.1%)
Canada	354	365	423	(3.0%)	(16.3%)
International	1,296	1,234	1,168	5.0%	11.0%
Worldwide	3,411	3,518	3,466	(3.0%)	(1.6%)
West Texas Intermediate Crude Prices (per barrel)	$97.91	$94.11	$94.90	4.0%	3.2%
Natural Gas Prices ($/mmbtu)	$ 3.72	$ 2.75	$ 4.00	35.3%	(7.0%)

* Averages for the years indicated. See sources below.

The following table details the U.S., Canadian, and international rig activity and West Texas Intermediate Oil prices for the past nine quarters ended December 31, 2013 on a quarterly basis:



	4Q11	1Q12	2Q12	3Q12	4Q12	1Q13	2Q13	3Q13	4Q13
Total Rigs	3,673	3,772	3,372	3,491	3,437	3,568	3,221	3,402	3,456
Canada	475	592	173	326	368	536	155	348	378
US	2,010	1,991	1,970	1,906	1,809	1,758	1,761	1,769	1,757
International	1,188	1,189	1,229	1,259	1,260	1,274	1,305	1,285	1,321
W. TX Int. (5)	$93.99	$102.88	$93.42	$92.18	$87.96	$94.34	$94.10	$105.84	$97.34

Source: Rig count: Baker Hughes, Inc. (www.bakerhughes.com); West Texas Intermediate Crude Price: Department of Energy, Energy Information Administration (www.eia.doe.gov).

The average price per barrel of West Texas Intermediate Crude was $97.91 per barrel in 2013, an increase of 4% over the average price for 2012 of $94.11 per barrel. The average natural gas price was $3.72 per mmbtu, an increase of 35% compared to the 2012 average of $2.75 per mmbtu. Average rig activity worldwide decreased 3% for the full year in 2013 compared to 2012. The average crude oil price for the fourth quarter of 2013 was $97.34 per barrel and natural gas was $3.84 per mmbtu.

At February 7, 2014, there were 2,392 rigs actively drilling in North America, compared to 2,020 rigs at December 31, 2013; an increase of 18.4% from year end 2013 levels. The price of oil increased to $99.98 per barrel and gas increased to $4.78 per mmbtu at February 7, 2014, representing a 1.8% increase in oil prices and an 11.9% increase in gas prices from the end of 2013.

EXECUTIVE SUMMARY

During 2013 National Oilwell Varco, Inc. earned $2.2 billion in income from continuing operations, or $5.09 per fully diluted share. Earnings from continuing operations per diluted share decreased 9% from prior year levels of $2.4 billion or $5.58 per fully diluted share. Excluding other costs (as defined in the "Non-GAAP Financial Measures and Reconciliations" in Results of Operations) from both years, diluted earnings per share of $5.17 in 2013 decreased 7% from $5.59 per share in 2012.

During 2013 revenue grew 12% from 2012, to $19.2 billion, and operating profit declined 6% from 2012, to $3.2 billion. Generally, 2013 benefitted from the acquisition of Robbins & Myers as well as higher international drilling activity, which saw international rig counts (as measured by Baker Hughes) increase 5% from 2012. This enabled all four of the Company's reporting segments to post higher year-over-year revenues in 2013.

For its fourth quarter ended December 31, 2013, the Company generated $630 million in net income from continuing operations, or $1.46 per fully diluted share, on $5.3 billion in revenue. Compared to the third quarter of 2013 revenue increased $439 million or 9% and net income from continuing operations increased $32 million. Compared to the fourth quarter of 2012, revenue increased $589 million or 13%, and net income from continuing operations decreased $7 million or 1%.

The fourth quarter of 2013 included pre-tax other costs of $16 million, the third quarter of 2013 included pre-tax other costs of $8 million and a pre-tax gain of $102 million resulting from the settlement of a legal claim, and the fourth quarter of 2012 included pre-tax other costs of $51 million, and a net $69 million tax benefit related to certain U.S. foreign tax credits in the quarter. Excluding the pre-tax gain, tax benefit and other costs from all periods, fourth quarter 2013 earnings were $1.49 per fully diluted share, compared to $1.24 per fully diluted share in the third quarter of 2013 and $1.40 per fully diluted share in the fourth quarter of 2012.

Operating profit excluding other costs and the litigation gains was $925 million or 17.4% of sales in the fourth quarter of 2013, compared to $791 million or 16.6% of sales in the third quarter of 2013, and $908 million or 19.3% of sales in the fourth quarter of 2012.

On May 30, 2014, the Company completed the previously announced spin-off ("spin-off") of its distribution business into an independent public company named NOW Inc., which trades on the New York Stock Exchange under the symbol "DNOW". After the close of the New York Stock Exchange on May 30, 2014, the stockholders of record as of May 22, 2014 (the "Record Date") received one share of NOW Inc. common stock for every four shares of NOV common shares as of the Record Date. No fractional shares of NOW Inc. common stock were distributed. Instead, the transfer agent aggregated any fractional shares into whole shares, sold those whole shares in the open market at prevailing rates and distributed the net cash proceeds, after deducting any taxes required to be withheld and any amount equal to all brokerage charges and commissions, pro rata to each holder who would otherwise have been entitled to receive fractional shares in the distribution.

Oil & Gas Equipment and Services Market

Worldwide, developed economies turned down in late 2008 as looming housing-related asset write-downs at major financial institutions paralyzed credit markets and sparked a serious global banking crisis. Major central banks responded vigorously through 2009, but a credit-driven worldwide economic recession developed nonetheless. Developed economies struggled to recover throughout 2010 and 2011, facing additional economic weakness related to potential sovereign debt defaults in Europe. As a result, commodity prices, including oil and gas prices, have been volatile. After rising steadily for six years to peak at around $140 per barrel (West Texas Intermediate Crude Prices) earlier in 2008, oil prices collapsed back to average $43 per barrel during the first quarter of 2009, but slowly recovered into the $100 per barrel range by mid-2011 where they held relatively steady since (although the fourth quarter of 2012 dipped to average $88 per barrel). After trading in the range of $6 to $9 an mmbtu from 2004 to 2008, North American gas prices declined to average $3.17 per mmbtu in the third quarter of 2009. Gas prices recovered modestly, trading up above $5 six months later, but then slowly settled into the $3 to $4 per mmbtu through 2011 before turning down sharply in early 2012 to the $2 range. In the fourth quarter 2012, gas prices recovered to average $3.40 per mmbtu; and, for the full year 2013, gas prices averaged $3.72 per mmbtu. The gas price collapse appears to be a direct result of rising gas supply out of unconventional shale reservoir development across North America, including gas associated with liquids production from shales.

The steadily rising oil and gas prices seen between 2003 and 2008 led to high levels of exploration and development drilling in many oil and gas basins around the globe by 2008, but activity slowed sharply in 2009 with lower oil and gas prices and tightening credit availability. Strengthening oil prices since then have led to steadily rising oil-drilling activity over the past two years.

The count of rigs actively drilling in the U.S. as measured by Baker Hughes (a good measure of the level of oilfield activity and spending) peaked at 2,031 rigs in September 2008, but decreased to a low of 876 in June, 2009. U.S. rig count increased steadily to 2,026 by late 2011, but began to decline with lower gas prices to average 1,809 rigs for the fourth quarter of 2012. The average U.S. rig count declined to 1,758 rigs in the first quarter of 2013, and remained relatively flat throughout the year. Many oil and gas operators reliant on external financing to fund their drilling programs significantly curtailed their drilling activity in 2009, but drilling recovered across North America as gas prices improved. Recently low gas prices have caused operators to trim drilling, driving the average U.S. gas rig count down 58% from the fourth quarter of 2011, to an average of 371 in the fourth quarter of 2013. However, with high oil prices, many have redirected drilling efforts towards unconventional shale plays targeting oil, rather than gas. For the fourth quarter of 2013, oil-directed drilling rose to almost 78% of the total domestic drilling effort, and remains near its highest levels in the U.S. since the early 1980's.

Most international activity is driven by oil exploration and production by national oil companies, which has historically been less susceptible to short-term commodity price swings; but, the international rig count exhibited modest declines nonetheless, falling from its September 2008 peak of 1,108 to 947 in August 2009. Recently, international drilling rebounded due to high oil prices, climbing back to average 1,321 rigs in the fourth quarter of 2013.

During 2009 the Company saw its Wellbore Technologies and Completion & Production Solutions margins were affected most acutely by a drilling downturn, through both volume and price declines. Resumption of drilling activity since enabled both of these segments to gain volume, stabilize and increase pricing, and improve margins over 2009 results. The Company's Rig Systems segment was less impacted by the 2009 downturn owing to its high level of contracted backlog, which it executed well. It posted higher revenues and operating profits in 2009 than 2008 as a result. The segment's revenues decreased in 2010 as its backlog declined, remained relatively flat in 2011, and rose 24% year-over-year in 2012 as orders for new offshore rigs increased.

The economic decline beginning in late 2008 followed an extended period of high drilling activity which fueled strong demand for oilfield services between 2003 and 2008. Incremental drilling activity through the upswing shifted toward harsh environments, employing increasingly sophisticated technology to find and produce reserves. Higher utilization of drilling rigs tested the capability of the world's fleet of rigs, much of which is old and of limited capability. Technology has advanced significantly since most of the existing rig fleet was built. The industry invested little during the late 1980's and 1990's on new drilling equipment, but drilling technology progressed steadily nonetheless, as the Company and its competitors continued to invest in new and better ways of drilling. As a consequence, the safety, reliability, and efficiency of new, modern rigs surpass the performance of most of the older rigs at work today. Drilling rigs are now being pushed to drill deeper wells, more complex wells, highly deviated wells and horizontal wells, tasks which require larger rigs with more capabilities. The drilling process effectively consumes the mechanical components of a rig, which wear out and need periodic repair or replacement. This process was accelerated by very high rig utilization and wellbore complexity. Drilling consumes rigs; more complex and challenging drilling consumes rigs faster.

The industry responded by launching many new rig construction projects since 2005, to 1.) retool the existing fleet of jackup rigs, 2.) replace older mechanical and DC electric land rigs with improved AC power, electronic controls, automatic pipe handling and rapid rigup and rigdown technology; and 3.) build out additional deepwater floating drilling rigs, including semisubmersibles and drillships, to employ recent advancements in deepwater drilling to exploit unexplored deepwater basins. We believe that the newer rigs offer considerably higher efficiency, safety, and capability, and that many will effectively replace a portion of the existing fleet.

As a result of the credit crisis and slowing drilling activity in 2009, orders in the Rig Systems segment declined below amounts flowing out of backlog as revenue, causing the segment's backlog to decline to $4.4 billion by the end of 2010. Since 2010 lows, the backlog increased steadily as drillers ordered more than the Company shipped out of backlog, and the segment finished the fourth quarter of 2013 at a record $15.0 billion. Of this backlog, 95% of the total is for equipment destined for offshore operations, with 5% destined for land. Equipment destined for international markets totaled 95% of the backlog.

Manufacturing lead time for orders in the Completion & Production Solutions segment's backlog is considerably shorter than that of the orders in Rig System's backlog. This segment's backlog has increased since 2009 as levels of drilling activity worldwide moved higher. Backlog in this segment also reached record levels, finishing the fourth quarter of 2013 at $1.6 billion. Of the $1.6 billion, 68% of the total is for equipment destined for offshore operations, with 32% destined for land. Equipment destined for international markets totaled 82%.

Segment Performance

Rig Systems

The Rig Systems segment generated $8.5 billion in revenues and $1.6 billion in operating profit or 18.9% of sales during 2013. Compared to the prior year, revenues improved 19% while operating profit dollars decreased 5% year-over-year. For the fourth quarter of 2013, the segment generated $2.4 billion in revenues and $453 million in operating profit or 18.9% of sales. Compared to the prior quarter, revenues increased $336 million or 16%, and operating profit increased $65 million. Compared to the fourth quarter of 2012, segment revenues grew $305 million or 15%, and operating profit decreased $76 million. Year-over-year operating leverage or flow-through was 25%. Margins have moved down steadily since mid-2010 due to an adverse mix shift in the segment, the addition of lower-margin acquisitions, and incremental expenses to support several strategic growth initiatives. The mix shift arises from offshore projects contracted at high prices in 2007 and 2008, which were subsequently manufactured in low cost environments in 2009 and 2010, resulting in high margins for the group which peaked in 2010. As these projects have been completed and replaced with lower priced projects, margins have gradually declined. Revenue out of backlog increased 20% sequentially and year-over-year. Orders for four deepwater floating rig equipment packages, and twenty five drilling equipment packages for jackup rigs, contributed to total order additions to backlog of $3.1 billion during the fourth quarter. Interest in offshore rig construction has remained strong as announced dayrates for deepwater offshore rigs remain strong, rig building costs have stabilized at attractive levels, and financing appears to be available for most established drillers. The segment also benefitted from the shipment of several land rigs in the fourth quarter.

Rig Aftermarket

The Rig Aftermarket segment generated $2.7 billion in revenues and $729 million in operating profit or 27.1% of sales during 2013. Compared to the prior year, revenues improved 26% while operating profit dollars increased 23% year-over-year. For the fourth quarter of 2013, the segment generated $759 million in revenues and $196 million in operating profit or 25.8% of sales. Compared to the prior quarter, revenues increased $47 million or 7%, and operating profit decreased $6 million. Compared to the fourth quarter of 2012, segment revenues increased $207 million or 38%, and operating profit increased $67 million. Year-over-year operating leverage or flow-through was 32%. Revenues have increased year-over-year since 2009 due to the growth in the installed base of NOV equipped rigs needing replacement parts and repair work, the fleet continued to come in for their 5 year re-certifications and additional aftermarket work required to comply with post Macondo regulations.

Wellbore Technologies

The Wellbore Technologies segment generated $5.2 billion in revenue and $915 million in operating profit, or 17.6% of sales, for the full year 2013. Compared to the prior year, revenue increased $27 million due to the addition of acquisitions, but operating profit declined $68 million, as the 8% year-over-year reduction in the U.S. drilling rig count (as measured by Baker Hughes) led to pricing pressures and under-absorption in a number of the segment's manufacturing and service facilities. For the fourth quarter of 2013, the segment generated $1.4 billion in revenue and $243 million in operating profit, or 15.2% of sales. Compared to the prior quarter, revenue decreased $24 million or 2%, and operating profit decreased $63 million. Compared to the fourth quarter of 2012, revenues increased $65 million, and operating profit increased $2 million. Revenues increased while year-over-year operating margins declined as the contributions from acquisitions integrated into the segment during 2013 were decretive to margins.

Completion & Production Solutions

The Completion & Production Solutions segment generated $4.3 billion in revenue and $613 million in operating profit, or 14.2% of sales, for the full year 2013. Compared to the prior year, revenue increased 8% helped by the acquisition of Robbins & Myers, but operating profit declined $71 million, as average year-over-year rig count increases internationally were not enough to offset declines in the U.S. and Canada. Margins were also negatively impacted by product mix as lower margin floating production and flexible pipe products replaced sales of more profitable pressure pumping and coiled tubing units. For the fourth quarter of 2013, the segment generated $1.2 billion in revenue and $175 million in operating profit, or 15.2% of sales. Compared to the prior quarter, revenue increased $60 million or 5%, and operating profit remained flat. Sequentially, drilling and completions activities in Canada continued to improve following the annual seasonal slow-down known as "break-up". This increase in activity created slight incremental demand for the segment's products and services. In the U.S., a relatively flat rig count, combined with fewer billing days in the quarter due to holidays, led to a sequential decline. Internationally, driven by some large year-end project shipments, revenues for the segment increased. Compared to the fourth quarter of 2012, revenues decreased $200 million and operating profit decreased $77 million, due to less demand for pressure pumping equipment, coiled tubing units, process equipment, chokes and reciprocating pumps. For the fourth quarter of 2013, approximately 51% of the segment's sales were into North American markets, and 49% of sales were into international markets.

Outlook

Following the credit market downturn, global recession, and lower commodity prices of 2009, we saw signs of stabilization and recovery in many of our markets in 2010 and into 2011, led by higher drilling activity in North America and slowly improving international drilling activity. Order levels for new deepwater drilling rigs have rebounded sharply, and the Rig Systems segment continues to experience a high level of interest as dayrates for deepwater offshore rigs remain at high levels. Still, margins, which were 18.9% in the fourth quarter of 2013, may continue to be challenged to expand beyond current levels a soft outlook for land drilling, low gas and natural gas liquids prices, higher costs of execution due to significantly compressed project timelines, continued flow through of lower priced projects, and incremental expenses to support long-term strategic growth initiatives. As the fleet of rigs worldwide continues to grow, and with the majority of those rigs equipped with NOV products, we are confident that our Aftermarket business will continue to supply more spare parts, servicing and repair to the fleet. Strict regulatory drilling requirements worldwide will keep demand for the segment's offerings at high levels.

Our outlook for the Company's Wellbore Technologies and Completion & Production Solutions segments remains closely tied to the rig count, particularly in North America. The fourth quarter saw U.S. rig counts relatively unchanged from the prior quarter, resulting in an average U.S. rig count in the fourth quarter that was down 3% from the average U.S. rig count in the fourth quarter of 2012. The fourth quarter saw average Canadian rig counts improve almost 9% sequentially and almost 3% year-over-year. As a result, revenues for both segments improved sequentially in Canada; however, for both the U.S. and Canada, pricing and volumes remain under pressure as pressure pumpers, drilling contractors and oil companies continue to carefully scrutinize operating and capital expenditures. Additionally, economic weakness may pressure oil prices, which could lead to further activity declines, particularly among North American operators which may rely on cash flows from gas production and/or external financing to fund their drilling operations. In contrast, activity generally seems to be continuing to increase in most international markets outside North America.

The Company believes it is well positioned, and should benefit from its strong balance sheet and capitalization, access to credit, global infrastructure, broad product and service offering, installed base of equipment, and a record level of contracted orders. In the event of a market downturn, the Company also believes that its long history of cost-control and downsizing in response to slowing market conditions, and of executing strategic acquisitions during difficult periods will enable it to capitalize on new opportunities to effect new organic growth and acquisition initiatives. Still the recovery of the world economy continues to move forward with a great deal of uncertainty. If such global economic uncertainties develop adversely, world oil and gas prices could be impacted which in turn could negatively impact the worldwide rig count and the Company's future financial results.

Results of Operations

Years Ended December 31, 2013 and December 31, 2012

The following table summarizes the Company's revenue and operating profit by operating segment in 2013 and 2012 (in millions):

	Years Ended December 31,		Variance	
	2013	2012	$	%
Revenue:				
Rig Systems	$ 8,450	$ 7,077	$1,373	19.4%
Rig Aftermarket	2,692	2,138	554	25.9%
Wellbore Technologies	5,211	5,184	27	0.5%
Completion & Production Solutions	4,309	3,994	315	7.9%
Eliminations	(1,441)	(1,199)	(242)	20.2%
Total Revenue	$ 19,221	$ 17,194	$2,027	11.8%
Operating Profit:				
Rig Systems	$ 1,594	$ 1,685	$ (91)	(5.4%)
Rig Aftermarket	729	594	135	22.7%
Wellbore Technologies	915	983	(68)	(6.9%)
Completion & Production Solutions	613	684	(71)	(10.4%)
Eliminations	(652)	(557)	(95)	17.1%
Total Operating Profit	$ 3,199	$ 3,389	$ (190)	(5.6%)
Operating Profit %:				
Rig Systems	18.9%	23.8%		
Rig Aftermarket	27.1%	27.8%		
Wellbore Technologies	17.6%	19.0%		
Completion & Production Solutions	14.2%	17.1%		
Total Operating Profit %	16.6%	19.7%		

Rig Systems

Revenue from Rig Systems for the year ended December 31, 2013 was $8,450 million, an increase of $1,373 million (19.4%) compared to the year ended December 31, 2012. Deepwater offshore demand as well as demand in international markets continues to be a driving force for the increase in revenue for Rig Systems as revenue out of backlog contributed $7,385 million in 2013. Increased sales of individual capital components and the acquisition of Robbins & Myers also contributed to the increase in revenue for Rig Systems. North American markets continue to see a decrease in demand for land drilling equipment. This is evidenced by a decrease in rig count in North America from 2012 and has resulted in a steady decline in sales of land rigs in the U.S. and Canada. The average rig count in the U.S. for the year ended 2013 decreased over 8% compared to the year ended 2012 and decreased 3% in Canada over the same period.

Operating profit from Rig Systems was $1,594 million for the year ended December 31, 2013, a decrease of $91 million (5.4%) compared to 2012. Operating profit percentage decreased to 18.9%, from 23.8% in 2012. The decrease in operating profit percentage continues to be primarily due to a shift in product mix as lower priced offshore projects replace projects contracted at higher prices in 2007 and 2008. In addition, our shipyard customers are compressing delivery schedules which have been leading to increased freight and personnel costs. Expenses associated with acquisition integration efforts, numerous strategic growth initiatives and capacity expansions worldwide have also contributed to the decrease in operating profit percentage.

Included in operating profit are certain other costs which include items such as transaction costs and inventory that was stepped up during purchase accounting. Other costs included in operating profit for Rig Systems were $21 million for the year ended December 31, 2013 and nil for the year ended December 31, 2012.

The Rig Systems segment monitors its capital equipment backlog to plan its business. New orders are added to backlog only when the Company receives a firm written order for major drilling rig components or a signed contract related to a construction project. The capital equipment backlog was $15.0 billion at December 31, 2013, an increase of $4.1 billion (38%) from backlog of $10.9 billion at December 31, 2012.

Rig Aftermarket

Revenue from Rig Aftermarket for the year ended December 31, 2013 was $2,692 million, an increase of $554 million (25.9%) compared to the year ended December 31, 2012. A growing installed base of NOV equipped rigs needing replacement parts and repair work, a fleet that continues to require re-certifications and additional aftermarket work required to comply with post Macondo regulations were the primary driving forces for the increase in revenue for this segment during 2013. North American markets continue to see a decrease in demand for land drilling equipment. This is evidenced by a decrease in rig count in North America from 2012 and has resulted in a steady decline in sales of land rigs in the U.S. and Canada. The average rig count in the U.S. for the year ended 2013 decreased over 8% compared to the year ended 2012 and decreased 3% in Canada over the same period.

Operating profit from Rig Aftermarket was $729 million for the year ended December 31, 2013, an increase of $135 million (22.7%) compared to 2012. Operating profit percentage decreased to 27.1%, from 27.8% in 2012. This decrease is attributed to the overall decline in the North America market activity which has led to pricing pressures and reduced operating profit percentage for the repair business. Operating profit percentage was also impacted in the North America with the integration of the Robbins & Myers repair business.

Wellbore Technologies

Revenue from Wellbore Technologies for the year ended December 31, 2013 was $5,211 million, an increase of $27 million (0.5%) compared to the year ended December 31, 2012. A nonrecurring gain of $102 million was recognized in the third quarter of 2013 related to a legal settlement. Offsetting this gain was lower revenue primarily due to lower North American drilling activity.

Operating profit from Wellbore Technologies was $915 million for the year ended December 31, 2013 compared to $983 million for 2012, a decrease of $68 million (6.9%). Operating profit percentage decreased to 17.6% from 19.0% in 2012. This decrease is primarily due to the overall decline in North American market activity which has led to pricing pressures across a number of products in the North American land market, as well as volume declines. Expenses associated with integrating recently acquired companies also contributed to the decrease in operating profit percentages.

Included in operating profit are certain other costs which include items such as transaction costs and the amortization of inventory that was stepped up during purchase accounting. Other costs included in operating profit for Wellbore Technologies were $41 million for the year ended December 31, 2013 and nil for the year ended December 31, 2012.

Completion & Production Solutions

Revenue from Completion & Production Solutions for the year ended December 31, 2013 was $4,309 million, an increase of $315 million (7.9%) compared to the year ended December 31, 2012. The increase is primarily due to the acquisition of Robbins & Myers during the first quarter of 2013, as well as having a full year of NOV Flexibles which was acquired in June of 2012. This was offset by the decline in pressure pumping equipment resulting from reduced capital spending by service companies.

Operating profit from Completion & Production Solutions was $613 million for the year ended December 31, 2013 compared to $684 million for 2012, a decrease of $71 million (10.4%). Operating profit percentage decreased to 14.2% from 17.1% in 2012. This decrease is primarily due to the overall decline in North American market activity which led to pricing pressures across a number of product lines, as well as volume declines affecting efficiencies. Expenses associated with integrating recently acquired companies as well as start-up expenses for our NOV Flexibles Brazil plant also contributed to the decrease in operating profit percentages.

Included in operating profit are certain other costs which include items such as transaction costs and the amortization of assets that were stepped up during purchase accounting. Other costs included in operating profit for Completion & Production Solutions were $82 million for the year ended December 31, 2013 and $90 million for the year ended December 31, 2012.

The Completion & Production Solutions segment monitors its capital equipment backlog to plan its business. New orders are added to backlog only when the Company receives a firm written order for major components or a signed contract related to a construction project. The capital equipment backlog was $1.6 billion at December 31, 2013, an increase of $0.3 million (23%) from backlog of $1.3 billion at December 31, 2012.

Eliminations

Eliminations in operating profit were $652 million for the year ended December 31, 2013 compared to $557 million for the year ended December 31, 2012. This increase was primarily due to increased intercompany sales activity for all segments resulting in higher intersegment eliminations. Sales from one segment to another generally are priced at estimated equivalent commercial selling prices; however, segments originating an external sale are credited with the full profit to the company. Eliminations include intercompany transactions conducted between the four reporting segments that are eliminated in consolidation. Intercompany transactions within each reporting segment are eliminated within each reporting segment.

Interest and financial costs

Interest and financial costs were $111 million for the year ended December 31, 2013 compared to $49 million for the year ended December 31, 2012. This increase is primarily due to an overall increase in average debt during 2013 compared 2012.

Equity Income in Unconsolidated Affiliates

Equity income in unconsolidated affiliates was $63 million for the year ended December 31, 2013 compared to $58 million for the year ended December 31, 2012. This increase was primarily due to increased equity earnings from the Company's 50.01% investment in Voest-Alpine Tubulars ("VAT") located in Kindberg, Austria.

Other income (expense), net

Other income (expense), net were expenses of $39 million for the year ended December 31, 2013 compared to expenses of $68 million for the year ended December 31, 2012. The change was primarily due to gains on the sale of certain assets during the second quarter of 2013, offset by foreign exchange losses and increased bank charges and fees.

Provision for income taxes

The effective tax rate for the year ended December 31, 2013 was 30.2%, compared to 28.9% for 2012. Compared to the U.S. statutory rate, the effective tax rate was positively impacted in the period by the effect of lower tax rates on income earned in foreign jurisdictions, that is considered to be permanently reinvested, a reduced tax rate in the UK and Norway, and the deduction in the U.S. for manufacturing activities. The effective tax rate was negatively impacted by foreign dividends net of foreign tax credits, foreign exchange gains for tax reporting in Norway, and the recognition of increased valuation allowances on certain deferred tax assets associated with excess foreign tax credits carried to future periods.

Years Ended December 31, 2012 and December 31, 2011

The following table summarizes the Company's revenue and operating profit by operating segment in 2012 and 2011 (in millions):

	Years Ended December 31,		Variance	
	2012	2011	$	%
Revenue:				
Rig Systems	$ 7,077	$ 5,686	$1,391	24.5%
Rig Aftermarket	2,138	1,876	262	14.0%
Wellbore Technologies	5,184	4,455	729	16.4%
Completion & Production Solutions	3,994	2,483	1,511	60.9%
Eliminations	(1,199)	(1,025)	(174)	17.0%
Total Revenue	$ 17,194	$ 13,475	$3,719	27.6%
Operating Profit:				
Rig Systems	$ 1,685	$ 1,562	$ 123	7.9%
Rig Aftermarket	594	528	66	12.5%
Wellbore Technologies	983	726	257	35.4%
Completion & Production Solutions	684	456	228	50.0%
Eliminations	(557)	(463)	(94)	20.3%
Total Operating Profit	$ 3,389	$ 2,809	$ 580	20.6%
Operating Profit %:				
Rig Systems	23.8%	27.5%		
Rig Aftermarket	27.8%	28.1%		
Wellbore Technologies	19.0%	16.3%		
Completion & Production Solutions	17.1%	18.4%		
Total Operating Profit %	19.7%	20.8%		

Rig Systems

Revenue from Rig Systems for the year ended December 31, 2012 was $7,077 million, an increase of $1,391 million (24.5%) compared to the year ended December 31, 2011. Deepwater offshore drilling worldwide and active shale plays in North America were the primary driving forces for the increase in revenue for this segment during the first half of 2012, resulting in increased rig construction. As the segment moved into the second half of 2012, it saw continued strong deepwater offshore demand as well as a strong demand in international markets with strong revenue growth in land rigs sold internationally. North American markets, however, saw a decrease in demand for land drilling as both gas and oil plays have decreased production. This is evidenced by a decrease in rig count in the U.S. during 2012 and has resulted in lower sales of land rigs and jackups in the U.S. as the segment moved into the second half of 2012. The average rig count in the U.S. during the fourth quarter of 2012 decreased to 1,809 rigs (9%) from the first quarter 2012 average of 1,991 rigs.

Operating profit from Rig Systems was $1,685 million for the year ended December 31, 2012, an increase of $123 million (7.9%) compared to 2011. Operating profit percentage decreased to 23.8%, from 27.5% in 2011. The decrease in operating profit was primarily due to a decrease in the average margin of revenue out of backlog as contracts signed during 2009 and 2010 contain less favorable margins compared to contracts won during the order ramp-up from 2005 to 2008.

The Rig Systems segment monitors its capital equipment backlog to plan its business. New orders are added to backlog only when the Company receives a firm written order for major drilling rig components or a signed contract related to a construction project. The capital equipment backlog was $10.9 billion at December 31, 2012, an increase of $1.7 billion (19%) from backlog of $9.2 billion at December 31, 2011.

Rig Aftermarket

Revenue from Rig Aftermarket for the year ended December 31, 2012 was $2,138 million, an increase of $262 million (14.0%) compared to the year ended December 31, 2011. A growing installed base of NOV equipped rigs needing replacement parts and repair work, a fleet that continues to require re-certifications and additional aftermarket work required to comply with post Macondo regulations were the primary driving forces for the increase in revenue for this segment during 2012. North American markets, however, saw a decrease in demand for land drilling as both gas and oil plays have decreased production. This is evidenced by a decrease in rig count in the U.S. during 2012. The average rig count in the U.S. during the fourth quarter of 2012 decreased to 1,809 rigs (9%) from the first quarter 2012 average of 1,991 rigs.

Operating profit from Rig Aftermarket was $594 million for the year ended December 31, 2012, an increase of $66 million (12.5%) compared to 2011. Operating profit percentage decreased to 27.8%, from 28.1% in 2011. This decrease in operating profit was primarily due to expenses associated with numerous strategic growth initiatives and capacity expansions worldwide.

Wellbore Technologies

Revenue from Wellbore Technologies for the year ended December 31, 2012 was $5,184 million, an increase of $729 million (16.4%) compared to the year ended December 31, 2011. Strong shale plays in North America lead to an increase in revenue for the Wellbore Technologies segment during the first half of 2012 compared to 2011. Acquisitions made during the year such as Zap-Lok Pipeline Systems, Inc. contributed to the increase in revenue for 2012 compared to 2011. Moving into the second half of 2012, while stronger than in 2011, compared to the first half of 2012, the segment saw a decrease in North American activity as evidenced in the decrease in U.S. rig count throughout the year.

Operating profit from Wellbore Technologies was $983 million for the year ended December 31, 2012 compared to $726 million for 2011, an increase of $257 million (35.4%). Operating profit percentage increased to 19.0% up from 16.3% in 2011. This increase is primarily due to increased volume, favorable pricing and cost reductions within most business units within the segment during the first half of 2012 compared to the same period in 2011. Most notably, growth in the drill pipe and Tuboscope products primarily lead to the increase in operating profit percentage.

Completion & Production Solutions

Revenue from Completion & Production Solutions for the year ended December 31, 2012 was $3,994 million, an increase of $1,511 million (60.9%) compared to the year ended December 31, 2011. Strong shale plays in North America lead to an increase in revenue for the Completion & Production Solutions segment during the first half of 2012 compared to 2011. Acquisitions made during the year such as Fiberspar Corporation, Conner Steel, Appco, Merpro, Enerflow and NKT as well as having a full year of Ameron contributed to the increase in revenue for 2012 compared to 2011. Compared to the first half of 2012, the segment saw a decrease in North American activity as evidenced in the decline in U.S. well count throughout the year.

Operating profit from Completion & Production Solutions was $684 million (which included $90 million in other costs related to acquisitions) for the year ended December 31, 2012 compared to $456 million for 2011, an increase of $228 million (50.0%). Operating profit percentage decreased to 17.1% down from 18.4% in 2011. Contributing to the decrease in operating profit were integration costs related to acquisitions as well as start-up costs associated with construction of an NOV Flexibles plant in Brazil. Coiled tubing equipment and wireline equipment sold later in the year were primarily driven by large international projects that were secured at lower than average margins.

The Completion & Production Solutions segment monitors its capital equipment backlog to plan its business. New orders are added to backlog only when the Company receives a firm written order for major components or a signed contract related to a construction project. The capital equipment backlog was $1.3 billion at both December 31, 2012 and 2011.

Eliminations

Eliminations in operating profit were $557 million for the year ended December 31, 2012 compared to $463 million for the year ended December 31, 2011. This increase was primarily due to the increased activity along all segments which in turn resulted in higher intersegment eliminations. Sales from one segment to another generally are priced at estimated equivalent commercial selling prices; however, segments originating an external sale are credited with the full profit to the company. Eliminations include intercompany transactions conducted between the four reporting segments that are eliminated in consolidation. Intercompany transactions within each reporting segment are eliminated within each reporting segment.

Equity Income in Unconsolidated Affiliates

Equity income in unconsolidated affiliates was $58 million for the year ended December 31, 2012 compared to $46 million for the year ended December 31, 2011. This increase was primarily due to increased equity earnings from the Company's 50.01% investment in Voest-Alpine Tubulars ("VAT") located in Kindberg, Austria.

Other income (expense), net

Other income (expense), net were expenses of $68 million for the year ended December 31, 2012 compared to $39 million for the year ended December 31, 2011. This increase was primarily due to foreign exchange losses and increased bank charges and fees.

Provision for income taxes

The effective tax rate for the year ended December 31, 2012 was 28.9%, compared to 32.0% for 2011. Compared to the U.S. statutory rate, the effective tax rate was positively impacted in the period by the effect of lower tax rates on income earned in foreign jurisdictions, that is considered to be permanently reinvested, foreign dividends net of foreign tax credits, the deduction in the U.S. for manufacturing activities and foreign exchange losses for tax reporting in Norway. The effective tax rate was negatively impacted by the recognition of increased valuation allowances on certain deferred tax assets associated with excess foreign tax credits carried to future periods.

Non-GAAP Financial Measures and Reconciliations

In an effort to provide investors with additional information regarding our results as determined by GAAP, we disclose various non-GAAP financial measures in our quarterly earnings press releases and other public disclosures. The primary non-GAAP financial measures we focus on are: (i) operating profit excluding nonrecurring items, (ii) operating profit percentage excluding nonrecurring items, and (iii) diluted earnings per share excluding nonrecurring items. Each of these financial measures excludes the impact of certain nonrecurring items and therefore has not been calculated in accordance with GAAP. A reconciliation of each of these non-GAAP financial measures to its most comparable GAAP financial measure is included below.

We use these non-GAAP financial measures internally to evaluate and manage the Company's operations because we believe it provides useful supplemental information regarding the Company's on-going economic performance. We have chosen to provide this information to investors to enable them to perform more meaningful comparisons of operating results and as a means to emphasize the results of on-going operations.

The following tables set forth the reconciliations of these non-GAAP financial measures to their most comparable GAAP financial measures (in millions, except per share data):

	Three Months Ended			Years Ended December 31,		
	December 31,		September 30,			
	2013	2012	2013	2013	2012	2011
Reconciliation of operating profit:						
GAAP operating profit	$ 909	$ 857	$ 884	$3,199	$3,389	$2,809
Litigation gain (1):						
Wellbore Technologies	—	—	(102)	(102)	—	—
Other costs (2):						
Rig Systems	5	—	4	21	—	7
Rig Aftermarket	—	—	—	—	—	—
Wellbore Technologies	2	—	2	41	—	10
Completion & Production Solutions	9	43	1	82	90	24
Eliminations	—	8	2	2	41	—
Operating profit excluding nonrecurring items	$ 925	$ 908	$ 791	$3,243	$3,520	$2,850

	Three Months Ended			Years Ended December 31,		
	December 31,		September 30,			
	2013	2012	2013	2013	2012	2011
Reconciliation of operating profit %:						
GAAP operating profit %	17.1%	18.2%	18.2%	16.6%	19.7%	20.8%
Nonrecurring items %	0.3%	1.1%	(1.6%)	0.3%	0.8%	0.3%
Operating profit % excluding nonrecurring items	17.4%	19.3%	16.6%	17.0%	20.5%	21.2%

	Three Months Ended			Years Ended December 31,		
	December 31,		September 30,			
	2013	2012	2013	2013	2012	2011
Reconciliation of diluted earnings per share:						
GAAP earnings per share (continuing operations)	$1.46	$ 1.49	$ 1.40	$ 5.09	$ 5.58	$ 4.50
Litigation gain (1)	—	—	(0.17)	(0.17)	—	—
Other costs (2)	0.03	0.07	0.01	0.25	0.17	0.07
Tax Benefits (3)	—	(0.16)	—	—	(0.16)	—
Earnings per share excluding nonrecurring items	$1.49	$ 1.40	$ 1.24	$ 5.17	$ 5.59	$ 4.57

(1) Included in Wellbore Technologies revenue and operating profit for the three months ended September 30, 2013 and for the year ended December 31, 2013, is a $102 million gain resulting from a legal settlement.

(2) Other costs primarily include items such as transaction costs and the amortization of backlog and inventory that was stepped up to fair value during purchase accounting, items which are included in operating profit. For the three months and for the year ended December 31, 2013, other costs included in operating profit were $16 million and $146 million, respectively. For the three months and for the year ended December, 2012, other costs included in operating profit were $51 million and $131 million, respectively. Other costs for the three months ended September 30, 2013 totaled $9 million. Certain other costs that are included in other income(expense), net were nil and $9 million for the three months and for the year ended December 31, 2013, respectively; $9 million and $12 million for the three months and for the year ended December 31, 2012, respectively; and $1 million for the three months ended September, 2013.

(3) Includes a net $69 million tax benefit related to certain U.S. foreign tax credits arising in the three months ended December 31, 2012. These credits resulted from a strategic reorganization of certain foreign operations to more fully integrate recently acquired businesses.

Liquidity and Capital Resources

The Company assesses liquidity in terms of its ability to generate cash to fund operating, investing and financing activities. The Company remains in a strong financial position, with resources available to reinvest in existing businesses, strategic acquisitions and capital expenditures to meet short- and long-term objectives. The Company believes that cash on hand, cash generated from expected results of operations and amounts available under its revolving credit facility will be sufficient to fund operations, anticipated working capital needs and other cash requirements including capital expenditures, debt and interest payments and dividend payments for the foreseeable future.

At December 31, 2013, the Company had cash and cash equivalents of $3,436 million, and total debt of $3,150 million. At December 31, 2012, cash and cash equivalents were $3,319 million and total debt was $3,149 million. A significant portion of the consolidated cash balances are maintained in accounts in various foreign subsidiaries and, if such amounts were transferred among countries or repatriated to the U.S., such amounts may be subject to additional tax obligations. Of the $3,436 million of cash and cash equivalents at December 31, 2013, approximately $3,102 million is held outside the U.S. If opportunities to invest in the U.S. are greater than available cash balances, the Company may choose to borrow against its $3.5 billion revolving credit facility. In August 2013, the Company initiated a commercial paper program, supported by its revolving credit facility.

The Company's outstanding debt at December 31, 2013 was $3,150 million and consisted of $151 million in 6.125% Senior Notes, $500 million in 1.35% Senior Notes, $1,396 million in 2.60% Senior Notes, $1,096 million in 3.95% Senior Notes, and other debt of $7 million.

At December 31, 2013, there were $947 million in outstanding letters of credit issued, resulting in $2,553 million of funds available under the Company's revolving credit facility.

The Company also had $3,056 million of additional outstanding letters of credit at December 31, 2013, primarily in Norway, that are under various bilateral committed letter of credit facilities. Other letters of credit are issued as bid bonds, advance payment bonds and performance bonds.

The following table summarizes our net cash provided by continuing operating activities, net cash used in continuing investing activities and net cash provided by (used in) continuing financing activities for the periods presented (in millions):

	Years Ended December 31,		
	2013	2012	2011
Net cash provided by continuing operating activities	$ 3,080	$ 632	$ 2,146
Net cash used in continuing investing activities	(2,910)	(2,301)	(1,424)
Net cash provided by (used in) continuing financing activities	(304)	2,584	(463)

Operating Activities

2013 vs 2012. Net cash provided by continuing operating activities was $3,080 million in 2013 compared to net cash provided by continuing operating activities of $632 million in 2012. Before changes in operating assets and liabilities, net of acquisitions, cash was provided by operations primarily through net income of $2,181 million plus non-cash charges of $402 million and $66 million in a dividend received from Voest-Alpine Tubulars, an unconsolidated affiliate, less $63 million in equity income. Net changes in operating assets and liabilities, net of acquisitions, provided $350 million in 2013 compared to $2,404 million used in 2012. This shift was primarily the result of increased cash collections in 2013, as prepayments and milestone invoicing outpaced costs incurred on projects. Further, greater fourth quarter 2013 equipment and product sales combined with improved inventory management lead to a $396 million inventory reduction in 2013. Cash tax payments in 2013 were also down compared to 2012.

2012 vs 2011. Net cash provided by continuing operating activities was $632 million in 2012 compared to net cash provided by continuing operating activities of $2,146 million in 2011. Before changes in operating assets and liabilities, net of acquisitions, cash was provided by operations primarily through net income of $2,375 million plus non-cash charges of $526 million and $61 million in a dividend received from Voest-Alpine Tubulars, an unconsolidated affiliate, less $58 million in equity income. Net changes in operating assets and liabilities, net of acquisitions, used $2,404 million in 2012 compared to $77 million used in 2011. Due to an increase in market activity during 2012 compared to 2011, revenue and backlog increased which is reflected in increased accounts receivable as well as a buildup in inventory. Increased market activity during 2012 also resulted in higher taxes paid, higher accounts payable and an increase in both costs in excess of billings and billings in excess of costs with costs incurred on major rig projects outpacing customer progress and milestone invoicing.

Investing Activities

2013 vs 2012. Net cash used in continuing investing activities was $2,910 million in 2013 compared to net cash used in continuing investing activities of $2,301 million in 2012. Net cash used in investing activities continued to primarily be the result of acquisition activity and capital expenditures. The Company used approximately $2.5 billion for the purpose of acquiring Robbins & Myers during the first quarter of 2013. For the acquisition of Robbins & Myers, the Company borrowed approximately $1.4 billion under the $3.5 billion revolving credit facility and used approximately $1.1 billion of cash on hand to fund the acquisition. By the end of 2013, the Company repaid all of $1.4 billion initially borrowed under its revolving credit facility. Due to the continued growth in the Company worldwide both organically and through acquisitions, the Company used $614 million during 2013 for capital expenditures compared to $569 million 2012.

2012 vs 2011. Net cash used in continuing investing activities was $2,301 million in 2012 compared to net cash used in continuing investing activities of $1,424 million in 2011. Net cash used in investing activities continued to primarily be the result of acquisition activity and capital expenditures both of which increased in 2012 compared to 2011. The Company used $1,767 million for the purpose of strategic acquisitions during 2012 compared to $1,008 million in 2011. In addition, due to the continued growth in the Company worldwide, both organically and through acquisition, the Company used $569 million during 2012 for capital expenditures compared to $479 million in 2011. During 2012, the Company used a combination of its cash on hand, borrowings from its revolving credit facility and the issuance of Senior Notes to fund its acquisitions and capital expenditures.

Financing Activities

2013 vs 2012. Net cash used in continuing financing activities was $304 million in 2013 shifting from net cash provided by continuing financing activities of $2,584 million in 2012. The change was primarily due to a decrease in net borrowings during 2013 and the Company receiving lower proceeds from stock options exercised compared to 2012. In addition, the Company doubled its quarterly dividend beginning in the second quarter of 2013.

2012 vs 2011. Net cash provided by continuing financing activities was $2,584 million in 2012 compared to net cash used in continuing financing activities of $463 million in 2011. The change related to a shift from the Company primarily repaying debt during 2011 to the Company refinancing its revolving credit facility, expanding it to $3.5 billion, and issuing three truanches of Senior Notes for a total of $3.0 billion in Senior Notes during 2012. Funds received as a result of borrowing in 2012 were used to finance working capital and acquisitions and to make tax payments. Proceeds from stock options exercised increased to $113 million during the year ended December 31, 2012 compared to $96 million for the year ended December 31, 2011. The Company again increased its dividend to $209 million during the year ended December 31, 2012 compared to $191 million for the year ended December 31, 2011.

Other

The effect of the change in exchange rates on cash flows was a decrease of $11 million, an increase of $9 million and a decrease of $19 million for the years ended December 31, 2013, 2012 and 2011, respectively.

We believe that cash on hand, cash generated from operations and amounts available under our credit facilities and from other sources of debt will be sufficient to fund operations, working capital needs, capital expenditure requirements, dividends and financing obligations.

We intend to pursue additional acquisition candidates, but the timing, size or success of any acquisition effort and the related potential capital commitments cannot be predicted. We continue to expect to fund future cash acquisitions primarily with cash flow from operations and borrowings, including the unborrowed portion of the revolving credit facility or new debt issuances, but may also issue additional equity either directly or in connection with acquisitions. There can be no assurance that additional financing for acquisitions will be available at terms acceptable to us.

A summary of the Company's outstanding contractual obligations at December 31, 2013 is as follows (in millions):

		Payment Due by Period			
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Contractual Obligations:					
Total debt	$3,150	$ 1	$ 153	$500	$2,496
Operating leases	1,076	218	285	158	415
Total Contractual Obligations	$4,226	$ 219	$ 438	$658	$2,911
Commercial Commitments:					
Standby letters of credit	$4,003	$1,905	$1,431	$526	$ 141

As of December 31, 2013, the Company entered into two capital lease agreements each covering a period of 25 years, totaling approximately $490 million. The first lease becomes effective in 2014 and the second in 2016.

As of December 31, 2013, the Company had $127 million of unrecognized tax benefits. This represents the tax benefits associated with various tax positions taken, or expected to be taken, on domestic and international tax returns that have not been recognized in our financial statements due to uncertainty regarding their resolution. Due to the uncertainty of the timing of future cash flows associated with these unrecognized tax benefits, we are unable to make reasonably reliable estimates of the period of cash settlement, if any, with the respective taxing authorities. Accordingly, unrecognized tax benefits have been excluded from the contractual obligations table above. For further information related to unrecognized tax benefits, see Note 14 to the Consolidated Financial Statements included in this Report.

Critical Accounting Policies and Estimates

In preparing the financial statements, we make assumptions, estimates and judgments that affect the amounts reported. We periodically evaluate our estimates and judgments that are most critical in nature which are related to revenue recognition under long-term construction contracts; allowance for doubtful accounts; inventory reserves; impairments of long-lived assets (excluding goodwill and other indefinite-lived intangible assets); goodwill and other indefinite-lived intangible assets; purchase price allocation of acquisitions; service and product warranties and income taxes. Our estimates are based on historical experience and on our future expectations that we believe are reasonable. The combination of these factors forms the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results are likely to differ from our current estimates and those differences may be material.

Revenue Recognition under Long-term Construction Contracts

The Company uses the percentage-of-completion method to account for certain long-term construction contracts in the Rig Systems segment. These long-term construction contracts include the following characteristics:

- the contracts include custom designs for customer specific applications;
- the structural design is unique and requires significant engineering efforts; and
- construction projects often have progress payments.

This method requires the Company to make estimates regarding the total costs of the project, progress against the project schedule and the estimated completion date, all of which impact the amount of revenue and gross margin the Company recognizes in each reporting period. The Company prepares detailed cost to complete estimates at the beginning of each project, taking into account all factors considered likely to affect gross margin. Significant projects and their related costs and profit margins are updated and reviewed at least quarterly by senior management. Factors that may affect future project costs and margins include shipyard access, weather, production efficiencies, availability and costs of labor, materials and subcomponents and other factors as mentioned in “Risk Factors.” These factors can significantly impact the accuracy of the Company’s estimates and materially impact the Company’s future reported earnings.

Historically, the Company’s estimates have been reasonably dependable regarding the recognition of revenues and gross profits on percentage-of-completion contracts. Based upon an analysis of percentage-of-completion contracts for all open contracts outstanding at December 31, 2012 and 2011 adjustments (representing the differences between the estimated and actual results) to all outstanding contracts resulted in net decreases to gross profit margins of 0.69% ($58 million on $8.4 billion of outstanding contracts) and 0.78% ($78 million on $9.6 billion of outstanding contracts) for the years ended December 31, 2013 and 2012, respectively. While the Company believes that its estimates on outstanding contracts at and in future periods will continue to be reasonably dependable under percentage-of-completion accounting, the factors identified in the preceding paragraph could result in significant adjustments in future periods. The Company has recorded revenue on outstanding contracts (on a contract-to-date basis) of $11 billion at December 31, 2013.

Allowance for Doubtful Accounts

The determination of the collectability of amounts due from customer accounts requires the Company to make judgments regarding future events and trends. Allowances for doubtful accounts are determined based on a continuous process of assessing the Company’s portfolio on an individual customer basis taking into account current market conditions and trends. This process consists of a thorough review of historical collection experience, current aging status of the customer accounts, and financial condition of the Company’s customers. Based on a review of these factors, the Company will establish or adjust allowances for specific customers. A substantial portion of the Company’s revenues come from international oil companies, international shipyards, international oilfield service companies, and government-owned or government-controlled oil companies. Therefore, the Company has significant receivables in many foreign jurisdictions. If worldwide oil and gas drilling activity or changes in economic conditions in foreign jurisdictions deteriorate, the creditworthiness of the Company’s customers could also deteriorate and they may be unable to pay these receivables, and additional allowances could be required. At December 31, 2013 and 2012, allowance for bad debts totaled $132 million and $120 million, or 2.6% and 2.7% of gross accounts receivable, respectively.

Historically, the Company’s charge-offs and provisions for the allowance for doubtful accounts have been immaterial to the Company’s consolidated financial statements. However, because of the risk factors mentioned above, changes in estimates could become material in future periods.

Inventory Reserves

Inventory is carried at the lower of cost or estimated net realizable value. The Company determines reserves for inventory based on historical usage of inventory on-hand, assumptions about future demand and market conditions, and estimates about potential alternative uses, which are usually limited. The Company's inventory consists of specialized spare parts, work in process, and raw materials to support ongoing manufacturing operations and the Company's large installed base of specialized equipment used throughout the oilfield. Customers rely on the Company to stock these specialized items to ensure that their equipment can be repaired and serviced in a timely manner. The Company's estimated carrying value of inventory therefore depends upon demand driven by oil and gas drilling and well remediation activity, which depends in turn upon oil and gas prices, the general outlook for economic growth worldwide, available financing for the Company's customers, political stability in major oil and gas producing areas, and the potential obsolescence of various types of equipment we sell, among other factors. At December 31, 2013 and 2012, inventory reserves totaled $396 million and $338 million, or 6.6% and 5.4% of gross inventory, respectively.

While inventory reserves and accruals have not had a material impact on the Company's financial results for the periods covered in this report, changes in worldwide oil and gas activity, or the development of new technologies which make older drilling technologies obsolete, could require the Company to record additional allowances to reduce the value of its inventory. Such changes in our estimates could be material under weaker market conditions or outlook.

Impairment of Long-Lived Assets (Excluding Goodwill and Other Indefinite-Lived Intangible Assets)

Long-lived assets, which include property, plant and equipment and identified intangible assets, comprise a significant amount of the Company's total assets. The Company makes judgments and estimates in conjunction with the carrying value of these assets, including amounts to be capitalized, depreciation and amortization methods and estimated useful lives.

The carrying values of these assets are reviewed for impairment 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. We estimate the fair value of these intangible and fixed assets using an income approach. This requires the Company to make long-term forecasts of its future revenues and costs related to the assets subject to review. These forecasts require assumptions about demand for the Company's products and services, future market conditions and technological developments. The forecasts are dependent upon assumptions regarding oil and gas prices, the general outlook for economic growth worldwide, available financing for the Company's customers, political stability in major oil and gas producing areas, and the potential obsolescence of various types of equipment we sell, among other factors. The financial and credit market volatility directly impacts our fair value measurement through our income forecast as well as our weighted-average cost of capital, both key assumptions used in our calculation. Changes to these assumptions, including, but not limited to: sustained declines in worldwide rig counts below current analysts' forecasts, collapse of spot and futures prices for oil and gas, significant deterioration of external financing for our customers, higher risk premiums or higher cost of equity, or any other significant adverse economic news could require a provision for impairment in a future period.

Goodwill and Other Indefinite-Lived Intangible Assets

The Company has approximately $9.0 billion of goodwill and $0.6 billion of other intangible assets with indefinite lives as of December 31, 2013, of which approximately $0.3 billion of goodwill relates to the distribution business we spun-off in May 2014. Generally accepted accounting principles require the Company to test goodwill and other indefinite-lived intangible assets for impairment at least annually or more frequently whenever events or circumstances occur indicating that goodwill or other indefinite-lived intangible assets might be impaired. Events or circumstances which could indicate a potential impairment include, but not limited to: further sustained declines in worldwide rig counts below current analysts' forecasts, further collapse of spot and futures prices for oil and gas, significant additional deterioration of external financing for our customers, higher risk premiums or higher cost of equity.

The implied fair value of goodwill is determined by deducting the fair value of a reporting unit's identifiable assets and liabilities from the fair value of that reporting unit as a whole. Fair value of the reporting units is determined in accordance with ASC Topic 820 "Fair Value Measurements and Disclosures" using significant unobservable inputs, or level 3 in the fair value hierarchy. These inputs are based on internal management estimates, forecasts and judgments, using a combination of three methods: discounted cash flow, comparable companies, and representative transactions. While the Company primarily uses the discounted cash flow method to assess fair value, the Company uses the comparable companies and representative transaction methods to validate the discounted cash flow analysis and further support management's expectations, where possible.

The discounted cash flow is based on management's short-term and long-term forecast of operating performance for each reporting unit. The two main assumptions used in measuring goodwill impairment, which bear the risk of change and could impact the Company's goodwill impairment analysis, include the cash flow from operations from each of the Company's individual business units and the weighted average cost of capital. The starting point for each of the reporting unit's cash flow from operations is the detailed annual plan or updated forecast. The detailed planning and forecasting process takes into consideration a multitude of factors including worldwide rig activity, inflationary forces, pricing strategies, customer analysis, operational issues, competitor analysis, capital spending requirements, working capital needs, customer needs to replace aging equipment, increased complexity of drilling, new technology, and existing backlog among other items which impact the individual reporting unit projections. Cash flows beyond the specific operating plans were estimated using a terminal value calculation, which incorporated historical and forecasted financial cyclical trends for each reporting unit and considered long-term earnings growth rates. The financial and credit market volatility directly impacts our fair value measurement through our weighted average cost of capital that we use to determine our discount rate. During times of volatility, significant judgment must be applied to determine whether credit changes are a short-term or long-term trend.

The annual impairment test is performed during the fourth quarter of each year. The valuation techniques used in the annual test were consistent with those used during previous testing. The inputs used in the annual test were updated for current market conditions and forecasts. During the review of its 2013 annual impairment test, the calculated fair values for all of the Company’s reporting units were considered substantially in excess of the respective reporting unit’s carrying value. Also, the fair value for all of the Company’s intangible assets with indefinite lives were considered substantially in excess of the respective asset carrying values, with one exception. This intangible asset, which represents a trade name within the Company’s Wellbore Technologies segment, had a calculated fair value approximately 13% in excess of its carrying value. Using the discounted cash flows approach, a decrease in the forecasted revenues of 20%, and/or an increase in the discount rate by 200 basis points could yield an impairment of approximately $25 million to $75 million. Based on its analysis, the Company did not report any impairment of goodwill and other indefinite-lived intangible assets for the years ended December 31, 2013, 2012 and 2011.

Purchase Price Allocation of Acquisitions

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

Service and Product Warranties

The Company provides service and warranty policies on certain of its products. The Company accrues liabilities under service and warranty policies based upon specific claims and a review of historical warranty and service claim experience in accordance with ASC Topic 450 “Contingencies” (“ASC Topic 450”). Adjustments are made to accruals as claim data and historical experience change. In addition, the Company incurs discretionary costs to service its products in connection with product performance issues and recognizes them when they are incurred. At December 31, 2013 and 2012, service and product warranties totaled $228 million and $194 million, respectively.

Income Taxes

The Company is a U.S. registered company and is subject to income taxes in the U.S. The Company operates through various subsidiaries in a number of countries throughout the world. Income taxes have been provided based upon the tax laws and rates of the countries in which the Company operates and income is earned.

The Company’s annual tax provision is based on taxable income, statutory rates and tax planning opportunities available in the various jurisdictions in which it operates. The determination and evaluation of the annual tax provision and tax positions involves the interpretation of the tax laws in the various jurisdictions in which the Company operates. It requires significant judgment and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of income, deductions and tax credits. Changes in tax laws, regulations, and treaties, foreign currency exchange restrictions or the Company’s level of operations or profitability in each jurisdiction could impact the tax liability in any given year. The Company also operates in many jurisdictions where the tax laws relating to the pricing of transactions between related parties are open to interpretation, which could potentially result in aggressive tax authorities asserting additional tax liabilities with no offsetting tax recovery in other countries.

The Company maintains liabilities for uncertain tax positions in jurisdictions of operation. The annual tax provision includes the impact of income tax provisions and benefits for changes to liabilities that the Company considers appropriate, as well as related interest. Uncertain tax positions primarily include potential challenges to intercompany pricing and certain operating expenses that may not be deductible in foreign jurisdictions. These exposures are resolved primarily through the settlement of audits within these tax jurisdictions or by judicial means. The Company is subject to audits by federal, state and foreign jurisdictions which may result in proposed assessments. The Company believes that an appropriate liability has been established for uncertain tax positions under the guidance in ASC Topic 740 "Income Taxes" ("ASC Topic 740"). However, actual results may differ materially from these estimates. The Company reviews these liabilities quarterly and to the extent audits or other events result in an adjustment to the liability accrued for a prior year, the effect will be recognized in the period of the event.

The Company currently has recorded valuation allowances that the Company intends to maintain until it is more likely than not the deferred tax assets will be realized. Income tax expense recorded in the future will be reduced to the extent of decreases in the Company's valuation allowances. The realization of remaining deferred tax assets is primarily dependent on future taxable income. Any reduction in future taxable income including but not limited to any future restructuring activities may require that the Company record an additional valuation allowance against deferred tax assets. An increase in the valuation allowance would result in additional income tax expense in such period and could have a significant impact on future earnings.

The Company has not provided for deferred taxes on the unremitted earnings of certain subsidiaries that are permanently reinvested. Should the Company make a distribution from the unremitted earnings of these subsidiaries, the Company may be required to record additional taxes. Unremitted earnings of these subsidiaries were $5,958 million and $4,523 million at December 31, 2013 and 2012, respectively. The Company makes a determination each period whether to permanently reinvest these earnings. If, as a result of these reassessments, the Company distributes these earnings in the future, additional tax liabilities would result, offset by any available foreign tax credits.

Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update No. 2013-02, "Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income" (ASU No. 2013-02), which is an update for Accounting Standards Codification Topic No. 220 "Comprehensive Income". The update improves the reporting of reclassifications out of accumulated other comprehensive income. The guidance was effective for the Company's interim and annual reporting periods beginning January 1, 2013, and applied prospectively. There was no significant impact to the Company's Consolidated Financial Statements from the adopted provisions of ASU No. 2013-02.

In March 2013, the FASB issued Accounting Standards Update No. 2013-05, "Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity (a consensus of the FASB Emerging Issues Task Force)." (ASU No. 2013-05), which amends Accounting Standards Codification Topic No. 830, "Foreign Currency Matters," and Accounting Standards Codification Topic No. 810, "Consolidation," to address diversity in practice related to the release of cumulative translation adjustments ("CTA") into earnings upon the occurrence of certain derecognition events. ASU No. 2013-05 precludes the release of CTA for derecognition events that occur within a foreign entity, unless such events represent a complete or substantially complete liquidation of the foreign entity; however, derecognition events related to investments in a foreign entity result in the release of all CTA related to the derecognized foreign entity, even when a noncontrolling financial interest is retained. ASU No. 2013-05 also amends Accounting Standards Codification Topic No. 805, "Business Combinations," for transactions that result in a company obtaining control of a business in a step acquisition by increasing an investment in a foreign entity from one accounted for under the equity method to one accounted for as a consolidated investment. ASU No. 2013-05 is effective for fiscal years beginning after December 15, 2013, and applied prospectively. Early adoption is permitted as of the beginning of the entity's fiscal year. The Company is currently assessing the impact ASU No. 2013-05 will have on its financial statements, but does not expect a significant impact from adoption of the pronouncement.

Forward–Looking Statements

Some of the information in this document contains, or has incorporated by reference, forward-looking statements. Statements that are not historical facts, including statements about our beliefs and expectations, are forward-looking statements. Forward-looking statements typically are identified by use of terms such as "may," "will," "expect," "anticipate," "estimate," and similar words, although some forward-looking statements are expressed differently. All statements herein regarding expected merger synergies are forward looking statements. You should be aware that our actual results could differ materially from results anticipated in the forward-looking statements due to a number of factors, including but not limited to changes in oil and gas prices, customer demand for our products and worldwide economic activity. You should also consider carefully the statements under "Risk Factors" which address additional factors that could cause our actual results to differ from those set forth in the forward-looking statements. Given these uncertainties, current or prospective investors are cautioned not to place undue reliance on any such forward-looking statements. We undertake no obligation to update any such factors or forward-looking statements to reflect future events or developments.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to changes in foreign currency exchange rates and interest rates. Additional information concerning each of these matters follows:

Foreign Currency Exchange Rates

We have extensive operations in foreign countries. The net assets and liabilities of these operations are exposed to changes in foreign currency exchange rates, although such fluctuations generally do not affect income since their functional currency is typically the local currency. These operations also have net assets and liabilities not denominated in the functional currency, which exposes us to changes in foreign currency exchange rates that impact income. During the years ended December 31, 2013, 2012 and 2011, the Company reported foreign currency losses were $24 million, $18 million and $10 million, respectively. Gains and losses are primarily due to exchange rate fluctuations related to monetary asset balances denominated in currencies other than the functional currency and adjustments to our hedged positions as a result of changes in foreign currency exchange rates. Strengthening of currencies against the U.S. dollar may create losses in future periods to the extent we maintain net assets and liabilities not denominated in the functional currency of the countries using the local currency as their functional currency.

Some of our revenues in foreign countries are denominated in U.S. dollars, and therefore, changes in foreign currency exchange rates impact our earnings to the extent that costs associated with those U.S. dollar revenues are denominated in the local currency. Similarly some of our revenues are denominated in foreign currencies, but have associated U.S. dollar costs, which also give rise to foreign currency exchange rate exposure. In order to mitigate that risk, we may utilize foreign currency forward contracts to better match the currency of our revenues and associated costs. We do not use foreign currency forward contracts for trading or speculative purposes.

The following table details the Company's foreign currency exchange risk grouped by functional currency and their expected maturity periods as of December 31, 2013 (in millions except for rates):

Functional Currency	As of December 31, 2013			December 31,
	2014	2015	Total	2012
CAD Buy USD/Sell CAD:				
Notional amount to buy (in Canadian dollars)	229	—	229	511
Average USD to CAD contract rate	1.0669	—	1.0669	0.9895
Fair Value at December 31, 2013 in U.S. dollars	1	—	1	5
Sell USD/Buy CAD:				
Notional amount to sell (in Canadian dollars)	51		51	255
Average USD to CAD contract rate	1.0485		1.0230	1.0230
Fair Value at December 31, 2013 in U.S. dollars	(1)	—	(1)	6
EUR Buy USD/Sell EUR:				
Notional amount to buy (in Euros)	9	—	9	7
Average USD to EUR contract rate	0.7596	0.7429	0.7590	0.7711
Fair Value at December 31, 2013 in U.S. dollars	1	—	1	—
Sell USD/Buy EUR:				
Notional amount to buy (in Euros)	343	1	344	205
Average USD to EUR contract rate	0.7401	0.7429	0.7401	0.7687
Fair Value at December 31, 2013 in U.S. dollars	9	—	9	4
KRW Buy USD/Sell KRW:				
Notional amount to buy (in South Korean won)	—	—	—	261
Average USD to KRW contract rate	—	—	—	918.8186
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
Sell USD/Buy KRW:				
Notional amount to buy (in South Korean won)	195,020	—	195,020	697
Average USD to KRW contract rate	1,114	—	1,114	1,013
Fair Value at December 31, 2013 in U.S. dollars	10	—	10	—

Functional Currency	As of December 31, 2013 2014	2015	Total	December 31, 2012
GBP Buy USD/Sell GBP:				
Notional amount to buy (in British Pounds Sterling)	11	—	11	47
Average USD to GBP contract rate	0.6142	—	0.6142	0.6149
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
Sell USD/Buy GBP:				
Notional amount to buy (in British Pounds Sterling)	66	7	73	37
Average USD to GBP contract rate	0.6208	0.6138	0.6201	0.6347
Fair Value at December 31, 2013 in U.S. dollars	2	—	2	2
USD Buy CAD/Sell USD:				
Notional amount to buy (in U.S. dollars)	6	9	15	—
Average CAD to USD contract rate	0.9464	0.9399	0.9431	—
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
Buy DKK/Sell USD:				
Notional amount to buy (in U.S. dollars)	57	14	71	42
Average DKK to USD contract rate	0.1810	0.1826	0.1813	0.1743
Fair Value at December 31, 2013 in U.S. dollars	1	—	1	—
Buy EUR/Sell USD:				
Notional amount to buy (in U.S. dollars)	609	164	773	664
Average EUR to USD contract rate	1.3371	1.3559	1.3411	1.3095
Fair Value at December 31, 2013 in U.S. dollars	18	3	21	8
Buy GBP/Sell USD:				
Notional amount to buy (in U.S. dollars)	31	11	42	18
Average GBP to USD contract rate	1.5756	1.5845	1.5779	1.6044
Fair Value at December 31, 2013 in U.S. dollars	1	—	1	—
Buy NOK/Sell USD:				
Notional amount to buy (in U.S. dollars)	1,257	620	1,877	1,065
Average NOK to USD contract rate	0.1650	0.1627	0.1642	0.1671
Fair Value at December 31, 2013 in U.S. dollars	(20)	(8)	(28)	66
Buy SGD/Sell USD:				
Notional amount to buy (in U.S. dollars)	9	5	15	31
Average SGD to USD contract rate	0.7967	0.7965	0.7966	0.8115
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
Sell CAD/Buy USD:				
Notional amount to buy (in U.S. dollars)	2	—	2	—
Average CAD to USD contract rate	0.9614	—	1.3625	—
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
Sell DKK/Buy USD:				
Notional amount to buy (in U.S. dollars)	11	—	11	12
Average DKK to USD contract rate	1.3625	—	1.3625	0.1749
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
Notional amount to sell (in U.S. dollars)	190	—	190	141
Average EUR to USD contract rate	1.3625	—	1.3109	1.3109
Fair Value at December 31, 2013 in U.S. dollars	(2)	—	(2)	(1)
Sell NOK/Buy USD:				
Notional amount to sell (in U.S. dollars)	335	51	385	274
Average NOK to USD contract rate	0.1658	0.1610	0.1634	0.1723
Fair Value at December 31, 2013 in U.S. dollars	6	—	6	(10)

Functional Currency	As of December 31, 2013 2014	2015	Total	December 31, 2012
Sell SGD/Buy USD:				
Notional amount to sell (in U.S. dollars)	1	—	1	—
Average SGD to USD contract rate	0.8000	—	0.8000	—
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
Sell RUB/Buy USD:				
Notional amount to sell (in U.S. dollars)	64	—	64	47
Average RUB to USD contract rate	0.0298	—	0.0298	0.0320
Fair Value at December 31, 2013 in U.S. dollars	(1)	—	(1)	—
Sell SEK/Buy USD:				
Notional amount to sell (in U.S. dollars)	1	—	1	—
Average SEK to USD contract rate	0.1529	—	0.1529	—
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
DKK Sell DKK/Buy USD:				
Notional amount to buy (in U.S. dollars)	111	—	111	111
Average DKK to USD contract rate	5.61	—	5.6126	5.6126
Fair Value at December 31, 2013 in U.S. dollars	—	—	—	—
Other Currencies				
Fair Value at December 31, 2013 in U.S. dollars	(2)	1	(1)	6
Total Fair Value at December 31, 2013 in U.S. dollars	23	(4)	19	86

The Company had other financial market risk sensitive instruments denominated in foreign currencies for transactional exposures totaling $875 million and translation exposures totaling $561 million as of December 31, 2013, excluding trade receivables and payables, which approximate fair value. These market risk sensitive instruments consisted of cash balances and overdraft facilities. The Company estimates that a hypothetical 10% movement of all applicable foreign currency exchange rates on the transactional exposures financial market risk sensitive instruments could affect net income by $57 million and the translational exposures financial market risk sensitive instruments could affect the future fair value by $56 million.

The counterparties to forward contracts are major financial institutions. The credit ratings and concentration of risk of these financial institutions are monitored on a continuing basis. In the event that the counterparties fail to meet the terms of a foreign currency contract, our exposure is limited to the foreign currency rate differential.

Historically, the Venezuelan government has devalued the country’s currency. During the first quarter of 2013, the Venezuelan government again officially devalued the Venezuelan bolivar against the U.S. dollar. As a result, the Company incurred approximately $12 million in devaluation charges in the first quarter of 2013. The Company’s net investment in Venezuela was $39 million at December 31, 2013.

Interest Rate Risk

At December 31, 2013, our long term borrowings consisted of $151 million in 6.125% Senior Notes, $500 million in 1.35% Senior Notes, $1,400 million in 2.60% Senior Notes and $1,100 million in 3.95% Senior Notes. We occasionally have borrowings under our credit facility, and a portion of these borrowings could be denominated in multiple currencies which could expose us to market risk with exchange rate movements. These instruments carry interest at a pre-agreed upon percentage point spread from either LIBOR, NIBOR or EURIBOR, or at the prime interest rate. Under our credit facility, we may, at our option, fix the interest rate for certain borrowings based on a spread over LIBOR, NIBOR or EURIBOR for 30 days to six months.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Attached hereto and a part of this report are financial statements and supplementary data listed in Item 15. “Exhibits and Financial Statement Schedules”.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

(i) Evaluation of disclosure controls and procedures

As required by SEC Rule 13a-15(b), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports that it files under the Exchange Act is accumulated and communicated to the Company’s management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Our principal executive officer and principal financial officer have concluded that our current disclosure controls and procedures were effective as of December 31, 2013 at the reasonable assurance level.

Pursuant to section 302 of the Sarbanes-Oxley Act of 2002, our Chief Executive Officer and Chief Financial Officer have provided certain certifications to the Securities and Exchange Commission. These certifications are included herein as Exhibits 31.1 and 31.2.

(ii) Internal Control Over Financial Reporting

(a) Management’s annual report on internal control over financial reporting.

The Company’s management report on internal control over financial reporting is set forth in this annual report on Page 65 and is incorporated herein by reference.

(b) Changes in internal control

There were no changes in the Company’s internal control over financial reporting that occurred during the Company’s last fiscal quarter covered by this report that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

National Oilwell Varco, Inc.'s management is responsible for establishing and maintaining adequate internal control over financial reporting. National Oilwell Varco, Inc.'s internal control system was 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.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

On February 20, 2013, the Company acquired Robbins & Myers. For purposes of determining the effectiveness of the Company's internal control over financial reporting, as disclosed in this report, management has excluded the internal controls of Robbins & Myers from its evaluation. The acquired business represented approximately 8% of our consolidated total assets at December 31, 2013 and 3% of consolidated revenues and 4% of our consolidated operating profit for the year ended December 31, 2013.

Management has used the 1992 framework set forth in the report entitled "Internal Control—Integrated Framework" published by the Committee of Sponsoring Organizations ("COSO") of the Treadway Commission to evaluate the effectiveness of the Company's internal control over financial reporting. Management has concluded that the Company's internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013, has been audited by Ernst & Young LLP, the independent registered public accounting firm which also has audited the Company's Consolidated Financial Statements included in this Annual Report on Form 10-K.

/s/ Clay C. Williams
Clay C. Williams
Chairman, President and Chief Executive Officer

/s/ Jeremy D. Thigpen
Jeremy D. Thigpen
Senior Vice President and Chief Financial Officer

Houston, Texas
February 14, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
National Oilwell Varco, Inc.

We have audited National Oilwell Varco, Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). National Oilwell Varco, Inc's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

As indicated in the accompanying Management's Report on Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Robbins & Myers, which is included in the 2013 consolidated financial statements of the Company and constituted approximately 8% of consolidated total assets at December 31, 2013 and 3% of consolidated revenues and 4% of consolidated operating profit for the year ended December 31, 2013. Our audit of internal control over financial reporting of the Company also did not include the evaluation of internal control over financial reporting of Robbins & Myers.

In our opinion, National Oilwell Varco, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2013 of National Oilwell Varco, Inc. and our report dated February 14, 2014 except for Notes 1, 15 and 17, as to which the date is August 14, 2014, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 14, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
National Oilwell Varco, Inc.

We have audited the accompanying consolidated balance sheets of National Oilwell Varco, Inc. as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in the index at item 15(2). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of National Oilwell Varco, Inc. as of December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), National Oilwell Varco, Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 14, 2014, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 14, 2014, except for Notes 1, 15 and 17,
as to which the date is August 14, 2014.

NATIONAL OILWELL VARCO, INC.
CONSOLIDATED BALANCE SHEETS
(In millions, except share data)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,436	$ 3,319
Receivables, net	4,896	4,320
Inventories, net	5,603	5,891
Costs in excess of billings	1,539	1,225
Deferred income taxes	373	349
Prepaid and other current assets	576	574
Total current assets	16,423	15,678
Property, plant and equipment, net	3,408	2,945
Deferred income taxes	372	413
Goodwill	9,049	7,172
Intangibles, net	5,055	4,743
Investment in unconsolidated affiliates	390	393
Other assets	115	140
Total assets	$34,812	$31,484
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,275	$ 1,200
Accrued liabilities	2,763	2,571
Billings in excess of costs	1,771	1,189
Current portion of long-term debt and short-term borrowings	1	1
Accrued income taxes	556	355
Deferred income taxes	312	333
Total current liabilities	6,678	5,649
Long-term debt	3,149	3,148
Deferred income taxes	2,292	1,997
Other liabilities	363	334
Total liabilities	12,482	11,128
Commitments and contingencies		
Stockholders' equity:		
Common stock—par value $.01; 1 billion shares authorized; 428,433,703 and 426,928,322 shares issued and outstanding at December 31, 2013 and December 31, 2012	4	4
Additional paid-in capital	8,907	8,743
Accumulated other comprehensive income (loss)	(4)	107
Retained earnings	13,323	11,385
Total Company stockholders' equity	22,230	20,239
Noncontrolling interests	100	117
Total stockholders' equity	22,330	20,356
Total liabilities and stockholders' equity	$34,812	$31,484

The accompanying notes are an integral part of these statements.

NATIONAL OILWELL VARCO, INC.
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per share data)

	Years Ended December 31,		
	2013	2012	2011
Revenue			
Sales	$15,489	$13,794	$10,659
Services	3,732	3,400	2,816
Total	19,221	17,194	13,475
Cost of revenue			
Cost of sales	11,107	9,335	7,055
Cost of services	3,010	2,816	2,124
Total	14,117	12,151	9,179
Gross profit	5,104	5,043	4,296
Selling, general and administrative	1,905	1,654	1,487
Operating profit	3,199	3,389	2,809
Interest and financial costs	(111)	(49)	(40)
Interest income	12	10	18
Equity income in unconsolidated affiliates	63	58	46
Other income (expense), net	(39)	(68)	(39)
Income from continuing operations before income taxes	3,124	3,340	2,794
Provision for income taxes	943	965	894
Income from continuing operations	2,181	2,375	1,900
Income from discontinued operations	147	108	85
Net income	2,328	2,483	1,985
Net income (loss) attributable to noncontrolling interests	1	(8)	(9)
Net income attributable to Company	$ 2,327	$ 2,491	$ 1,994
Per share data:			
Basic:			
Income from continuing operations	$ 5.11	$ 5.61	$ 4.52
Income from discontinued operations	$ 0.35	$ 0.25	$ 0.21
Net income attributable to Company	$ 5.46	$ 5.86	$ 4.73
Diluted:			
Income from continuing operations	$ 5.09	$ 5.58	$ 4.50
Income from discontinued operations	$ 0.35	$ 0.25	$ 0.20
Net income attributable to Company	$ 5.44	$ 5.83	$ 4.70
Cash dividends per share	$ 0.91	$ 0.49	$ 0.45
Weighted average shares outstanding:			
Basic	426	425	422
Diluted	428	427	424

The accompanying notes are an integral part of these statements.

NATIONAL OILWELL VARCO, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31, 2013	2012	2011
Net income	$2,328	$2,483	$1,985
Other comprehensive income (loss) (net of tax):			
Currency translation adjustments	(115)	64	(65)
Derivative financial instruments	(37)	99	(63)
Change in defined benefit plans	41	(33)	14
Comprehensive income	2,217	2,613	1,871
Net income (loss) attributable to noncontrolling interests	1	(8)	(9)
Comprehensive income attributable to Company	$2,216	$2,621	$1,880

The accompanying notes are an integral part of these statements.

NATIONAL OILWELL VARCO, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2013	2012	2011
Cash flows from operating activities:			
Income from continuing operations	$ 2,181	$ 2,375	$ 1,900
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	738	616	549
Deferred income taxes	(336)	(90)	(341)
Stock-based compensation	92	80	73
Excess tax benefit from stock-based compensation	(20)	(25)	(22)
Equity income in unconsolidated affiliates	(63)	(58)	(46)
Dividend from unconsolidated affiliates	66	61	45
Other	72	77	65
Change in operating assets and liabilities, net of acquisitions:			
Receivables	(516)	(492)	(630)
Inventories	238	(974)	(555)
Costs in excess of billings	(314)	(632)	222
Prepaid and other current assets	41	(221)	(42)
Accounts payable	18	40	183
Billings in excess of costs	582	324	354
Income taxes payable	217	(408)	283
Other assets/liabilities, net	84	(41)	108
Net cash provided by continuing operating activities	3,080	632	2,146
Discontinued operations	317	(12)	(3)
Net cash provided by operating activities	3,397	620	2,143
Cash flows from investing activities:			
Purchases of property, plant and equipment	(614)	(569)	(479)
Business acquisitions, net of cash acquired	(2,397)	(1,767)	(1,008)
Dividend from unconsolidated affiliate	—	—	13
Other, net	101	35	50
Net cash used in continuing investing activities	(2,910)	(2,301)	(1,424)
Discontinued operations	(54)	(1,127)	(34)
Net cash used in investing activities	(2,964)	(3,428)	(1,458)
Cash flows from financing activities:			
Borrowings against lines of credit and other debt	2,609	5,575	—
Payments against lines of credit and other debt	(2,609)	(2,937)	(390)
Cash dividends paid	(389)	(209)	(191)
Proceeds from stock options exercised	58	113	96
Excess tax benefit from stock-based compensation	20	25	22
Other	7	17	—
Net cash provided by (used in) continuing financing activities	(304)	2,584	(463)
Discontinued operations	(1)	(1)	(1)
Net cash provided by (used in) financing activities	(305)	2,583	(464)
Effect of exchange rates on cash	(11)	9	(19)
Increase (decrease) in cash and cash equivalents	117	(216)	202
Cash and cash equivalents, beginning of period	3,319	3,535	3,333
Cash and cash equivalents, end of period	$ 3,436	$ 3,319	$ 3,535
Supplemental disclosures of cash flow information:			
Cash payments during the period for:			
Interest	$ 111	$ 40	$ 44
Income taxes	$ 1,099	$ 1,572	$ 945

The accompanying notes are an integral part of these statements.

NATIONAL OILWELL VARCO, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In millions)

	Shares Outstanding	Common Stock	Additional Paid in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Company Stockholders' Equity	Noncontrolling Interests	Total Stockholders' Equity
Balance at December 31, 2010	421	$ 4	$ 8,353	$ 91	$ 7,300	$ 15,748	$ 114	$ 15,862
Net income attributable to Company	—	—	—	—	1,994	1,994	(9)	1,985
Other comprehensive income, net	—	—	—	(114)	—	(114)	—	(114)
Cash dividends, $.45 per common share	—	—	—	—	(191)	(191)	—	(191)
Dividends to noncontrolling interests	—	—	—	—	—	—	(17)	(17)
Noncontrolling interest contribution	—	—	—	—	—	—	21	21
Stock-based compensation	—	—	73	—	—	73	—	73
Common stock issued	3	—	96	—	—	96	—	96
Withholding taxes	—	—	(9)	—	—	(9)	—	(9)
Excess tax benefit from stock-based compensation	—	—	22	—	—	22	—	22
Balance at December 31, 2011	424	$ 4	$ 8,535	$ (23)	$ 9,103	$ 17,619	$ 109	$ 17,728
Net income attributable to Company	—	—	—	—	2,491	2,491	(8)	2,483
Other comprehensive loss, net	—	—	—	130	—	130	—	130
Cash dividends, $.49 per common share	—	—	—	—	(209)	(209)	—	(209)
Dividends to noncontrolling interests	—	—	—	—	—	—	(4)	(4)
Noncontrolling interest contribution	—	—	—	—	—	—	20	20
Stock-based compensation	—	—	80	—	—	80	—	80
Common stock issued	3	—	113	—	—	113	—	113
Withholding taxes	—	—	(10)	—	—	(10)	—	(10)
Excess tax benefit from stock-based compensation	—	—	25	—	—	25	—	25
Balance at December 31, 2012	427	$ 4	$ 8,743	$ 107	$ 11,385	$ 20,239	$ 117	$ 20,356
Net income attributable to Company	—	—	—	—	2,327	2,327	1	2,328
Other comprehensive income, net	—	—	—	(111)	—	(111)	—	(111)
Cash dividends, $.91 per common share	—	—	—	—	(389)	(389)	—	(389)
Dividends to noncontrolling interests	—	—	—	—	—	—	(3)	(3)
Noncontrolling interest contribution	—	—	—	—	—	—	10	10
Disposal of noncontrolling interest, net	—	—	—	—	—	—	(25)	(25)
Stock-based compensation	—	—	92	—	—	92	—	92
Common stock issued	1	—	58	—	—	58	—	58
Withholding taxes	—	—	(6)	—	—	(6)	—	(6)
Excess tax benefit from stock-based compensation	—	—	20	—	—	20	—	20
Balance at December 31, 2013	428	$ 4	$ 8,907	$ (4)	$ 13,323	$ 22,230	$ 100	$ 22,330

The accompanying notes are an integral part of these statements.

1. Organization and Basis of Presentation

Nature of Business

We design, construct, manufacture and sell comprehensive systems, components, and products used in oil and gas drilling and production, provide oilfield services and supplies, and distribute products and provide supply chain integration services to the upstream oil and gas industry. Our revenues and operating results are directly related to the level of worldwide oil and gas drilling and production activities and the profitability and cash flow of oil and gas companies, drilling contractors and oilfield service companies, which in turn are affected by current and anticipated prices of oil and gas. Oil and gas prices have been, and are likely to continue to be, volatile.

Basis of Consolidation

The accompanying Consolidated Financial Statements include the accounts of National Oilwell Varco, Inc. and its consolidated subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation. Investments that are not wholly-owned, but where we exercise control, are fully consolidated with the equity held by minority owners and their portion of net income (loss) reflected as noncontrolling interests in the accompanying consolidated financial statements. Investments in unconsolidated affiliates, over which we exercise significant influence, but not control, are accounted for by the equity method.

On May 30, 2014, the Company completed the spin-off of its distribution business into an independent public company named NOW Inc. In conjunction with the spin-off of NOW Inc. the Company reviewed its reporting and management structure, and effective April 1, 2014, reorganized the Rig Technology, Petroleum Services & Supplies and remaining operations of Distribution & Transmission reporting segments into four new reporting segments. The new reporting segments are Rig Systems, Rig Aftermarket, Wellbore Technologies and Completion & Production Solutions.

As a result of these changes, the Consolidated Financial Statements have been revised to reflect the spin-off of NOW Inc. as discontinued operations. In addition, Note 1, Note 2, Note 4, Note 12 and Note 15 to the Consolidated Financial Statements have been revised to reflect the spin-off off of NOW Inc., as discontinued operations and to recast the financial information to reflect the new reporting segments. Note 14, Note 16 and Note 17 have been revised to reflect the spin-off of NOW Inc., only.

2. Summary of Significant Accounting Policies

Fair Value of Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, receivables, and payables approximated fair value because of the relatively short maturity of these instruments. Cash equivalents include only those investments having a maturity date of three months or less at the time of purchase.

Derivative Financial Instruments

Accounting Standards Codification ("ASC") Topic 815, "Derivatives and Hedging" ("ASC Topic 815") requires companies to recognize all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, a company must designate the hedging instrument, based upon the exposure being hedged, as a fair value hedge, cash flow hedge, or a hedge of a net investment in a foreign operation.

The Company records all derivative financial instruments at their fair value in its Consolidated Balance Sheet. Except for certain non-designated hedges discussed below, all derivative financial instruments that the Company holds are designated as cash flow hedges and are highly effective in offsetting movements in the underlying risks. Such arrangements typically have terms between two and 24 months, but may have longer terms depending on the underlying cash flows being hedged, typically related to the projects in our backlog.

Inventories

Inventories consist of raw materials, work-in-process and oilfield and industrial finished products, manufactured equipment and spare parts. Inventories are stated at the lower of cost or market using the first-in, first-out or average cost methods. Allowances for excess and obsolete inventories are determined based on our historical usage of inventory on-hand as well as our future expectations related to our installed base and the development of new products. The allowance, which totaled $396 million and $338 million at December 31, 2013 and 2012, respectively, is the amount necessary to reduce the cost of the inventory to its net realizable value.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost. Expenditures for major improvements that extend the lives of property and equipment are capitalized while minor replacements, maintenance and repairs are charged to operations as incurred. Disposals are removed at cost less accumulated depreciation with any resulting gain or loss reflected in operations. Depreciation is provided using the straight-line method over the estimated useful lives of individual items. Depreciation expense was $381 million, $315 million and $275 million for the years ended December 31, 2013, 2012 and 2011, respectively. The estimated useful lives of the major classes of property, plant and equipment are included in Note 6 to the consolidated financial statements.

Long-lived Assets

We record impairment losses on long-lived assets used in operations when events and circumstances indicate that the assets are impaired and the undiscounted cash flows estimated to be generated by those assets are less than the carrying amount of those assets. The carrying value of assets used in operations that are not recoverable is reduced to fair value if lower than carrying value. In determining the fair market value of the assets, we consider market trends and recent transactions involving sales of similar assets, or when not available, discounted cash flow analysis. There have been no impairments of long-lived assets for the years ended December 31, 2013, 2012 and 2011.

Intangible Assets

The Company has approximately $9.0 billion of goodwill and $5.1 billion of identified intangible assets at December 31, 2013. Generally accepted accounting principles require the Company to test goodwill and other indefinite-lived intangible assets for impairment at least annually or more frequently whenever events or circumstances occur indicating that such assets might be impaired.

Goodwill is identified by segment as follows (in millions):

	Rig Systems	Rig Aftermarket	Wellbore Technologies	Completion & Production Solutions	Discontinued Operations	Total
Balance at December 31, 2011	$ 943	$ 556	$ 3,683	$ 917	$ 52	$6,151
Goodwill acquired during period	145	89	80	395	291	1,000
Currency translation adjustments and other	9	4	6	2	—	21
Balance at December 31, 2012	$1,097	$ 649	$ 3,769	$ 1,314	$ 343	$7,172
Goodwill acquired during the period	179	256	665	803	—	1,903
Currency translation adjustments and other	3	1	(9)	(11)	(10)	(26)
Balance at December 31, 2013	$1,279	$ 906	$ 4,425	$ 2,106	$ 333	$9,049

Identified intangible assets with determinable lives consist primarily of customer relationships, trademarks, trade names, patents, and technical drawings acquired in acquisitions, and are being amortized on a straight-line basis over the estimated useful lives of 2-30 years. Amortization expense of identified intangibles is expected to be approximately $360 million in each of the next five years. Included in intangible assets are approximately $643 million of indefinite-lived trade names.

The net book values of identified intangible assets are identified by segment as follows (in millions):

	Rig Systems	Rig Aftermarket	Wellbore Technologies	Completion & Production Solutions	Discontinued Operations	Total
Balance at December 31, 2011	$ 56	$ 92	$ 3,134	$ 771	$ 20	$4,073
Additions to intangible assets	18	—	8	897	58	981
Amortization	(14)	(3)	(203)	(81)	(4)	(305)
Currency translation adjustments and other	2	—	3	(11)	—	(6)
Balance at December 31, 2012	$ 62	$ 89	$ 2,942	$ 1,576	$ 74	$4,743
Additions to intangible assets	190	59	286	161	—	696
Amortization	(21)	(6)	(217)	(113)	(6)	(363)
Currency translation adjustments and other	1	—	(12)	(10)	—	(21)
Balance at December 31, 2013	$ 232	$ 142	$ 2,999	$ 1,614	$ 68	$5,055

Identified intangible assets by major classification consist of the following (in millions):

	Gross	Accumulated Amortization	Net Book Value
December 31, 2012:			
Customer relationships	$3,522	$ (907)	$ 2,615
Trademarks	877	(152)	725
Indefinite-lived trade names	643	—	643
Other	1,087	(327)	760
Total identified intangibles	$6,129	$ (1,386)	$ 4,743
December 31, 2013:			
Customer relationships	$4,093	$ (1,147)	$ 2,946
Trademarks	893	(195)	698
Indefinite-lived trade names	643	—	643
Other	1,175	(407)	768
Total identified intangibles	$6,804	$ (1,749)	$ 5,055

The Company performed its annual impairment analysis for its goodwill and indefinite-lived intangible assets during the fourth quarter of 2013, 2012 and 2011 each resulting in no impairment. The valuation techniques used in the annual test were consistent with those used during previous testing. The inputs used in the annual test were updated for current market conditions and forecasts.

Foreign Currency

The functional currency for most of our foreign operations is the local currency. The cumulative effects of translating the balance sheet accounts from the functional currency into the U.S. dollar at current exchange rates are included in accumulated other comprehensive income (loss). Revenues and expenses are translated at average exchange rates in effect during the period. Certain other foreign operations, including our operations in Norway, use the U.S. dollar as the functional currency. Accordingly, financial statements of these foreign subsidiaries are remeasured to U.S. dollars for consolidation purposes using current rates of exchange for monetary assets and liabilities and historical rates of exchange for nonmonetary assets and related elements of expense. Revenue and expense elements are remeasured at rates that approximate the rates in effect on the transaction dates. For all operations, gains or losses from remeasuring foreign currency transactions into the functional currency are included in income. Net foreign currency transaction losses were $24 million, $18 million and $10 million for the years ending December 31, 2013, 2012 and 2011, respectively, and are included in other income (expense) in the accompanying statement of operations.

Historically, the Venezuelan government has devalued the country's currency. During the first quarter of 2013, the Venezuelan government again officially devalued the Venezuelan bolivar against the U.S. dollar. As a result, the Company incurred approximately $12 million in devaluation charges in the first quarter of 2013. The Company's net investment in Venezuela was $39 million at December 31, 2013.

Revenue Recognition

The Company's products and services are sold based upon purchase orders or contracts with the customer that include fixed or determinable prices and that do not generally include right of return or other similar provisions or other significant post delivery obligations. Except for certain construction contracts and drill pipe sales described below, the Company records revenue at the time its manufacturing process is complete, the customer has been provided with all proper inspection and other required documentation, title and risk of loss has passed to the customer, collectability is reasonably assured and the product has been delivered. Customer advances or deposits are deferred and recognized as revenue when the Company has completed all of its performance obligations related to the sale. The Company also recognizes revenue as services are performed. The amounts billed for shipping and handling cost are included in revenue and related costs are included in cost of sales.

Revenue Recognition under Long-term Construction Contracts

The Company uses the percentage-of-completion method to account for certain long-term construction contracts in the Rig Systems and Completion & Production Solutions segments. These long-term construction contracts include the following characteristics:

- the contracts include custom designs for customer specific applications;
- the structural design is unique and requires significant engineering efforts; and
- construction projects often have progress payments.

This method requires the Company to make estimates regarding the total costs of the project, progress against the project schedule and the estimated completion date, all of which impact the amount of revenue and gross margin the Company recognizes in each reporting period. The Company prepares detailed cost estimates at the beginning of each project. Significant projects and their related costs and profit margins are updated and reviewed at least quarterly by senior management. Factors that may affect future project costs and margins include shipyard access, weather, production efficiencies, availability and costs of labor, materials and subcomponents and other factors. These factors can impact the accuracy of the Company's estimates and materially impact the Company's current and future reported earnings.

The asset, "Costs in excess of billings," represents revenues recognized in excess of amounts billed. The liability, "Billings in excess of costs," represents billings in excess of revenues recognized.

Drill Pipe Sales

For drill pipe sales, if requested in writing by the customer, delivery may be satisfied through delivery to the Company's customer storage location or to a third-party storage facility. For sales transactions where title and risk of loss have transferred to the customer but the supporting documentation does not meet the criteria for revenue recognition prior to the products being in the physical possession of the customer, the recognition of the revenues and related inventory costs from these transactions are deferred until the customer takes physical possession.

Service and Product Warranties

The Company provides service and warranty policies on certain of its products. The Company accrues liabilities under service and warranty policies based upon specific claims and a review of historical warranty and service claim experience in accordance with ASC Topic 450 "Contingencies" ("ASC Topic 450"). Adjustments are made to accruals as claim data and historical experience change. In addition, the Company incurs discretionary costs to service its products in connection with product performance issues and accrues for them when they are encountered. The Company monitors the actual cost of performing these discretionary services and adjusts the accrual based on the most current information available.

The changes in the carrying amount of service and product warranties are as follows (in millions):

Balance at December 31, 2011	$211
Net provisions for warranties issued during the year	51
Amounts incurred	(76)
Currency translation adjustments and other	8
Balance at December 31, 2012	$194
Net provisions for warranties issued during the year	101
Amounts incurred	(73)
Currency translation adjustments and other	6
Balance at December 31, 2013	$228

Income Taxes

The liability method is used to account for income taxes. Deferred tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities and are measured using the enacted tax rates that will be in effect when the differences are expected to reverse. Valuation allowances are established when necessary to reduce deferred tax assets to amounts which are more likely than not to be realized.

Concentration of Credit Risk

We grant credit to our customers, which operate primarily in the oil and gas industry. Concentrations of credit risk are limited because we have a large number of geographically diverse customers, thus spreading trade credit risk. We control credit risk through credit evaluations, credit limits and monitoring procedures. We perform periodic credit evaluations of our customers' financial condition and generally do not require collateral, but may require letters of credit for certain international sales. Credit losses are provided for in the financial statements. Allowances for doubtful accounts are determined based on a continuous process of assessing the Company's portfolio on an individual customer basis taking into account current market conditions and trends. This process consists of a thorough review of historical collection experience, current aging status of the customer accounts, and financial condition of the Company's customers. Based on a review of these factors, the Company will establish or adjust allowances for specific customers. Accounts receivable are net of allowances for doubtful accounts of approximately $132 million and $120 million at December 31, 2013 and 2012.

Stock-Based Compensation

Compensation expense for the Company's stock-based compensation plans is measured using the fair value method required by ASC Topic 718 "Compensation – Stock Compensation" ("ASC Topic 718"). Under this guidance the fair value of stock option grants and restricted stock is amortized to expense using the straight-line method over the shorter of the vesting period or the remaining employee service period.

The Company provides compensation benefits to employees and non-employee directors under share-based payment arrangements, including various employee stock option plans.

Total compensation cost that has been charged against income for all share-based compensation arrangements was $86 million, $74 million and $68 million for 2013, 2012 and 2011, respectively. The total income tax benefit recognized in the income statement for all share-based compensation arrangements was $26 million, $22 million and $15 million for 2013, 2012 and 2011, respectively.

Environmental Liabilities

When environmental assessments or remediations are probable and the costs can be reasonably estimated, remediation liabilities are recorded on an undiscounted basis and are adjusted as further information develops or circumstances change.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect reported and contingent amounts of assets and liabilities as of the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Such estimates include but are not limited to, estimated losses on accounts receivable, estimated costs and related margins of projects accounted for under percentage-of-completion, estimated realizable value on excess and obsolete inventory, contingencies, estimated liabilities for litigation exposures and liquidated damages, estimated warranty costs, estimates related to pension accounting, estimates related to the fair value of reporting units for purposes of assessing goodwill and other indefinite-lived intangible assets for impairment and estimates related to deferred tax assets and liabilities, including valuation allowances on deferred tax assets. Actual results could differ from those estimates.

Contingencies

The Company accrues for costs relating to litigation claims and other contingent matters, including liquidated damage liabilities, when such liabilities become probable and reasonably estimable. In circumstances where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than others, the low end of the range is accrued. Such estimates may be based on advice from third parties or on management's judgment, as appropriate. Revisions to contingent liabilities are reflected in income in the period in which different facts or information become known or circumstances change that affect the Company's previous judgments with respect to the likelihood or amount of loss. Amounts paid upon the ultimate resolution of contingent liabilities may be materially different from previous estimates and could require adjustments to the estimated reserves to be recognized in the period such new information becomes known.

Net Income Attributable to Company Per Share

The following table sets forth the computation of weighted average basic and diluted shares outstanding (in millions, except per share data):

	Years Ended December 31,		
	2013	2012	2011
Numerator:			
Income from continuing operations	$2,180	$2,383	$1,909
Income from discontinued operations	$ 147	$ 108	$ 85
Net income attributable to Company	$2,327	$2,491	$1,994
Denominator:			
Basic—weighted average common shares outstanding	426	425	422
Dilutive effect of employee stock options and other unvested stock awards	2	2	2
Diluted outstanding shares	428	427	424
Per share data:			
Basic:			
Income from continuing operations	$ 5.11	$ 5.61	$ 4.52
Income from discontinued operations	$ 0.35	$ 0.25	$ 0.21
Net income attributable to Company	$ 5.46	$ 5.86	$ 4.73
Diluted:			
Income from continuing operations	$ 5.09	$ 5.58	$ 4.50
Income from discontinued operations	$ 0.35	$ 0.25	$ 0.20
Net income attributable to Company	$ 5.44	$ 5.83	$ 4.70
Cash dividends per share	$ 0.91	$ 0.49	$ 0.45

ASC Topic 260, "Earnings Per Share" ("ASC Topic 260") requires companies with unvested participating securities to utilize a two-class method for the computation of net income attributable to Company per share. The two-class method requires a portion of net income attributable to Company to be allocated to participating securities, which are unvested awards of share-based payments with non-forfeitable rights to receive dividends or dividend equivalents, if declared. Net income attributable to Company allocated to these participating securities was immaterial for the years ended December 31, 2013, 2012 and 2011 and therefore not excluded from net income attributable to Company per share calculation.

The Company had stock options outstanding that were anti-dilutive totaling 7 million, 5 million, and 3 million at December 31, 2013, 2012 and 2011, respectively.

Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update No. 2013-02, "Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income" (ASU No. 2013-02), which is an update for Accounting Standards Codification Topic No. 220 "Comprehensive Income". The update improves the reporting of reclassifications out of accumulated other comprehensive income. The guidance was effective for the Company's interim and annual reporting periods beginning January 1, 2013, and applied prospectively. There was no significant impact to the Company's Consolidated Financial Statements from the adopted provisions of ASU No. 2013-02.

In March 2013, the FASB issued Accounting Standards Update No. 2013-05, "Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity (a consensus of the FASB Emerging Issues Task Force)." (ASU No. 2013-05), which amends Accounting Standards Codification Topic No. 830, "Foreign Currency Matters," and Accounting Standards Codification Topic No. 810, "Consolidation," to address diversity in practice related to the release of cumulative translation adjustments ("CTA") into earnings upon the occurrence of certain derecognition events. ASU No. 2013-05 precludes the release of CTA for derecognition events that occur within a foreign entity, unless such events represent a complete or substantially complete liquidation of the foreign entity; however, derecognition events related to investments in a foreign entity result in the release of all CTA related to the derecognized foreign entity, even when a noncontrolling financial interest is retained. ASU No. 2013-05 also amends Accounting Standards Codification Topic No. 805, "Business Combinations," for transactions that result in a company obtaining control of a business in a step acquisition by increasing an investment in a foreign entity from one accounted for under the equity method to one accounted for as a consolidated investment. ASU No. 2013-05 is effective for fiscal years beginning after December 15, 2013, and applied prospectively. Early adoption is permitted as of the beginning of the entity's fiscal year. The Company is currently assessing the impact ASU No. 2013-05 will have on its financial statements, but does not expect a significant impact from adoption of the pronouncement.

3. Derivative Financial Instruments

The Company is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is foreign currency exchange rate risk. Forward contracts against various foreign currencies are entered into to manage the foreign currency exchange rate risk on forecasted revenues and expenses denominated in currencies other than the functional currency of the operating unit (cash flow hedge). Other forward exchange contracts against various foreign currencies are entered into to manage the foreign currency exchange rate risk associated with certain firm commitments denominated in currencies other than the functional currency of the operating unit (fair value hedge). In addition, the Company will enter into non-designated forward contracts against various foreign currencies to manage the foreign currency exchange rate risk on recognized nonfunctional currency monetary accounts (non-designated hedge).

At December 31, 2013, the Company has determined that the fair value of its derivative financial instruments representing assets of $59 million and liabilities of $40 million (primarily currency related derivatives) are determined using level 2 inputs (inputs other than quoted prices in active markets for identical assets and liabilities that are observable either directly or indirectly for substantially the full term of the asset or liability) in the fair value hierarchy as the fair value is based on publicly available foreign exchange and interest rates at each financial reporting date. At December 31, 2013, the net fair value of the Company’s foreign currency forward contracts totaled a net asset of $19 million.

At December 31, 2013, the Company’s financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when the Company’s financial instruments are in net liability positions. We do not use derivative financial instruments for trading or speculative purposes.

Cash Flow Hedging Strategy

To protect against the volatility of forecasted foreign currency cash flows resulting from forecasted revenues and expenses, the Company has instituted a cash flow hedging program. The Company hedges portions of its forecasted revenues and expenses denominated in nonfunctional currencies with forward contracts. When the U.S. dollar strengthens against the foreign currencies, the decrease in present value of future foreign currency revenues and expenses is offset by gains in the fair value of the forward contracts designated as hedges. Conversely, when the U.S. dollar weakens, the increase in the present value of future foreign currency cash flows is offset by losses in the fair value of the forward contracts.

For derivative instruments that are designated and qualify as a cash flow hedge (i.e., hedging the exposure to variability in expected future cash flows that is subject to a particular currency risk), the effective portion of the gain or loss on the derivative instrument is reported as a component of Other Comprehensive Income and reclassified into earnings in the same line item associated with the forecasted transaction and in the same period or periods during which the hedged transaction affects earnings (e.g., in “revenues” when the hedged transactions are cash flows associated with forecasted revenues). The remaining gain or loss on the derivative instrument in excess of the cumulative change in the present value of future cash flows of the hedged item, if any (i.e., the ineffective portion), or hedge components excluded from the assessment of effectiveness, is recognized in the Consolidated Statements of Income during the current period.

At December 31, 2013 and 2012, the Company had the following outstanding foreign currency forward contracts that were entered into to hedge nonfunctional currency cash flows from forecasted revenues and expenses (in millions):

	Currency Denomination			
Foreign Currency	December 31, 2013		December 31, 2012	
Norwegian Krone	NOK	10,503	NOK	6,281
Euro	€	406	€	389
U.S. Dollar	$	357	$	357
Danish Krone	DKK	278	DKK	134
British Pound Sterling	£	23	£	6
Singapore Dollar	SGD	17	SGD	14
Canadian Dollar	CAD	16	CAD	—

Non-designated Hedging Strategy

The Company enters into forward exchange contracts to hedge certain nonfunctional currency monetary accounts. The purpose of the Company's foreign currency hedging activities is to protect the Company from risk that the eventual U.S. dollar equivalent cash flows from the nonfunctional currency monetary accounts will be adversely affected by changes in the exchange rates.

For derivative instruments that are non-designated, the gain or loss on the derivative instrument subject to the hedged risk (i.e., nonfunctional currency monetary accounts) is recognized in other income (expense), net in current earnings.

The Company had the following outstanding foreign currency forward contracts that hedge the fair value of nonfunctional currency monetary accounts (in millions):

	Currency Denomination			
Foreign Currency	**December 31, 2013**		**December 31, 2012**	
Norwegian Krone	NOK	3,257	NOK	1,684
Russian Ruble	RUB	2,149	RUB	1,467
U.S. Dollar	$	715	$	967
Euro	€	310	€	225
Danish Krone	DKK	177	DKK	177
British Pound Sterling	£	14	£	9
Swedish Krone	SEK	4	SEK	5
Singapore Dollar	SGD	3	SGD	24
Canadian Dollar	CAD	3	CAD	2
Brazilian Real	BRL	—	BRL	135

The Company has the following fair values of its derivative instruments and their balance sheet classifications (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Fair Value December 31,		Balance Sheet Location	Fair Value December 31,	
		2013	2012		2013	2012
Derivatives designated as hedging instruments under ASC Topic 815						
Foreign exchange contracts	Prepaid and other current assets	$35	$ 57	Accrued liabilities	$ 18	$ 5
Foreign exchange contracts	Other Assets	5	24	Other Liabilities	9	1
Total derivatives designated as hedging instruments under ASC Topic 815		$40	$ 81		$ 27	$ 6
Derivatives not designated as hedging instruments under ASC Topic 815						
Foreign exchange contracts	Prepaid and other current assets	$19	$ 24	Accrued liabilities	$ 13	$ 13
Total derivatives not designated as hedging instruments under ASC Topic 815		$19	$ 24		$ 13	$ 13
Total derivatives		$59	$105		$ 40	$ 19

The Effect of Derivative Instruments on the Consolidated Statements of Income
($ in millions)

Derivatives Designated as Hedging Instruments under ASC Topic 815	Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) (a)		Location of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		Location of Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion and Amount Excluded from Effectiveness Testing) (b)	
	Years Ended December 31,			Years Ended December 31,			Years Ended December 31,	
	2013	2012		2013	2012		2013	2012
			Revenue	16	(6)			
Foreign exchange contracts	(42)	105	Cost of revenue	(6)	(26)	Other income (expense), net	12	8
Total	(42)	105		10	(32)		12	8

Derivatives Not Designated as Hedging Instruments under ASC Topic 815	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives	
		Years Ended December 31,	
		2013	2012
Foreign exchange contracts	Other income (expense), net	18	19
Total		18	19

(a) The Company expects that $(16) million of the Accumulated Other Comprehensive Income (Loss) will be reclassified into earnings within the next twelve months with an offset by gains from the underlying transactions resulting in no impact to earnings or cash flow.

(b) The amount of gain (loss) recognized in income represents nil related to the ineffective portion of the hedging relationships for the each of the years ended December 31, 2013 and 2012, and $12 million and $8 million related to the amount excluded from the assessment of the hedge effectiveness for the years ended December 31, 2013 and 2012, respectively.

4. Acquisitions and Investments

2013

On February 20, 2013, the Company completed its acquisition of all of the shares of Robbins & Myers, Inc. ("R&M"), a U.S.-based designer and manufacturer of products and systems for the oil and gas industry. Under the merger agreement for this transaction, R&M shareholders received $60.00 in cash for each common share for an aggregate purchase price of $2,378 million, net of cash acquired. In addition to R&M, the Company completed five acquisitions and other investments for an aggregate purchase price of $19 million, net of cash acquired.

The Company has included the financial results of R&M in its consolidated financial statements as of the date of acquisition with components of the R&M operations included in each of the Company's segments. The Company believes the acquisition of R&M will advance its strategic goal of providing a broader selection of products and services to its customers.

The following table displays the total preliminary purchase price allocation for the R&M acquisition. The table summarizes the fair values of the assets acquired and liabilities assumed at the date of acquisition (in millions):

Current assets, net of cash acquired	$ 428
Property, plant and equipment	250
Intangible assets	894
Goodwill	1,590
Other assets	49
Total assets acquired	3,211
Current liabilities	186
Deferred taxes	524
Other liabilities	123
Total liabilities	833
Cash consideration, net of cash acquired	$2,378

The Company has allocated $894 million to identifiable intangible assets (19 year weighted-average life). The intangible assets are amortizable and are comprised of: $635 million of customer relationships (18 year weighted-average life), $170 million of patents (20 year weighted-average life), $86 million of trademarks (20 year weighted-average life), and $3 million of other intangible assets (1 year weighted-average life). The amount allocated to goodwill represents the excess of the purchase price over the fair value of the net assets acquired. Goodwill specifically includes the expected synergies and other benefits that the Company believes will result from combining its operations with those of businesses acquired and other intangible assets that do not qualify for separate recognition, such as assembled workforce in place at the date of acquisition. Goodwill resulting from the R&M acquisition is not deductible for tax purposes. Pro forma information is not included because the results of the acquired operations would not have materially impacted the Company's consolidated operating results.

2012

In the year ended December 31, 2012, the Company completed 17 acquisitions for an aggregate purchase price of $2,880 million, net of cash acquired. These acquisitions included:

- All the shares of NKT Flexibles I/S ("NKT"), a Denmark-based designer and manufacturer of flexible pipe products and systems for the offshore oil and gas industry, acquired on April 4, 2012. The Company reported the NKT results within its Completion & Production Solutions segment from the date of acquisition.
- All the shares of Enerflow Industries Inc. (U.S.) and certain assets of Enerflow Industries Inc. (Canada) ("Enerflow"), a Canada-based fabricator and manufacturer of pressure pumping, blending, and cementing equipment for use primarily in Canada and the U.S., acquired on May 16, 2012. The Company reported the Enerflow results within its Completion & Production Solutions segment from the date of acquisition.
- All the shares of Wilson Distribution Holdings ("Wilson"), a U.S.-based distributor of pipe, valves and fittings as well as mill, tool and safety products and services, acquired on May 31, 2012. The Company reported the Wilson results within its discontinued operations from the date of acquisition.
- All the shares of CE Franklin Ltd. ("CE Franklin"), a Canada-based distributor of pipe, valves, flanges, fittings, production equipment, tubular products and other general oilfield supplies to oil and gas producers in Canada as well as to the oil sands, refining, heavy oil, petrochemical, forestry and mining industries, acquired on July 19, 2012. The Company reported the CE Franklin results within its discontinued operations from the date of acquisition.
- All the shares of Fiberspar Corporation ("Fiberspar"), a U.S.-based manufacturer of fiberglass-reinforced spoolable pipe for the oil and gas industry, acquired on October 10, 2012. The Company reported the Fiberspar results within its Wellbore Technologies segment from the date of acquisition.

The following table displays the total purchase price allocation for the 2012 acquisitions and summarizes the fair values of the assets acquired and liabilities assumed at the date of acquisition (in millions):

	Total
Current assets, net of cash acquired	$1,441
Property, plant and equipment	248
Intangible assets	981
Goodwill	1,000
Other assets	2
Total assets acquired	3,672
Current liabilities	585
Long-term debt	1
Other liabilities	206
Total liabilities	792
Cash consideration, net of cash acquired	$2,880

The Company allocated $981 million to intangible assets (18 year weighted-average life). The intangible assets are amortizable and are comprised of: $473 million of customer relationships (20 year weighted-average life), $159 million of trademarks (16 year weighted-average life), and $348 million of other intangible assets (17 year weighted-average life). Goodwill specifically includes the expected synergies and other benefits that the Company believes will result from combining its operations with those of businesses acquired and other intangible assets that do not qualify for separate recognition, such as assembled workforce in place at the date of each acquisition. The $1,000 million allocated to goodwill represents the excess of the purchase price over the fair value of the net assets acquired. Goodwill resulting from the NKT and CE Franklin acquisitions and a portion of the Enerflow acquisition is not deductible for tax purposes. Pro forma information is not included because the results of the acquired operations would not have materially impacted the Company's consolidated operating results.

2011

The Company completed nine acquisitions for an aggregate purchase price of $1,038 million, net of cash acquired. These acquisitions included:

- The shares of Ameron International Corporation ("Ameron"), a U.S.-based manufacturer of highly engineered products and materials for the chemical, industrial, energy, transportation and infrastructure markets.
- The shares of Conner Steel Products Holding Company, a U.S.-based manufacturer of storage and handling equipment for the oilfield services industry.

The following table displays the total purchase price allocation for the 2011 acquisitions and summarizes the fair values of the assets acquired and liabilities assumed at the date of acquisition (in millions):

	Ameron	All Other Acquisitions	Total
Current assets, net of cash acquired	$ 245	$ 106	$ 351
Property, plant and equipment	402	41	443
Intangible assets	142	131	273
Goodwill	199	178	377
Other assets	59	14	73
Total assets acquired	1,047	470	1,517
Current liabilities	154	80	234
Long-term debt	16	—	16
Other liabilities	173	56	229
Total liabilities	343	136	479
Cash consideration, net of cash acquired	$ 704	$ 334	$1,038

The Company allocated $273 million to intangible assets (16 year weighted-average life), comprised of: $119 million of customer relationships (14 year weighted-average life), $39 million of trademarks (35 year weighted-average life), and $115 million of other intangible assets (12 year weighted-average life).

Each of the acquisitions was accounted for using the purchase method of accounting and, accordingly, the results of operations of each business are included in the consolidated results of operations from the date of acquisition. A summary of the acquisitions follows (in millions):

	Years Ended December 31,		
	2013	2012	2011
Fair value of assets acquired, net of cash acquired	$ 3,329	$ 3,672	$ 1,517
Cash paid, net of cash acquired	(2,397)	(2,880)	(1,038)
Liabilities assumed, debt issued and noncontrolling interest	$ 932	$ 792	$ 479
Excess purchase price over fair value of net assets acquired	$ 1,903	$ 1,000	$ 377

5. Inventories, net

Inventories consist of (in millions):

	December 31, 2013	December 31, 2012
Raw materials and supplies	$1,175	$1,268
Work in process	798	905
Finished goods and purchased products	3,630	3,718
Total	$5,603	$5,891

6. Property, Plant and Equipment

Property, plant and equipment consist of (in millions):

	Estimated Useful Lives	December 31, 2013	December 31, 2012
Land and buildings	5-35 Years	$ 1,494	$ 1,348
Operating equipment	3-15 Years	2,960	2,463
Rental equipment	3-12 Years	758	712
		5,212	4,523
Less: Accumulated Depreciation		(1,804)	(1,578)
		$ 3,408	$ 2,945

7. Accrued Liabilities

Accrued liabilities consist of (in millions):

	December 31, 2013	December 31, 2012
Customer prepayments and billings	$ 673	$ 699
Accrued vendor costs	531	444
Compensation	516	511
Warranty	228	194
Taxes (non income)	188	150
Insurance	131	108
Accrued commissions	97	77
Fair value of derivatives	31	18
Interest	11	14
Other	357	356
Total	$2,763	$2,571

8. Costs and Estimated Earnings on Uncompleted Contracts

Costs and estimated earnings on uncompleted contracts consist of (in millions):

	December 31, 2013	December 31, 2012
Costs incurred on uncompleted contracts	$ 7,608	$ 5,731
Estimated earnings	3,553	3,160
	11,161	8,891
Less: Billings to date	11,393	8,855
	$ (232)	$ 36
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 1,539	$ 1,225
Billings in excess of costs and estimated earnings on uncompleted contracts	(1,771)	(1,189)
	$ (232)	$ 36

9. Debt

Debt consists of (in millions):

	December 31, 2013	December 31, 2012
Senior Notes, interest at 6.125% payable semiannually, principal due on August 15, 2015	151	151
Senior Notes, interest at 1.35% payable semiannually, principal due on December 1, 2017	500	500
Senior Notes, interest at 2.6% payable semiannually, principal due on December 1, 2022	1,396	1,395
Senior Notes, interest at 3.95% payable semiannually, principal due on December 1, 2042	1,096	1,096
Other	7	7
Total debt	3,150	3,149
Less current portion	1	1
Long-term debt	$3,149	$3,148

Principal payments of debt for years subsequent to 2013 are as follows (in millions):

2014	$ 1
2015	153
2016	—
2017	500
2018	—
Thereafter	2,496
	$3,150

The Company has a $3.5 billion, five-year unsecured revolving credit facility which expires September 28, 2018, following a one year extension executed in September 2013. In August 2013, the Company initiated a commercial paper program. Borrowings under the commercial paper program are classified as long-term as the program is supported by the $3.5 billion, five-year revolving credit facility. At December 31, 2013, there were no commercial paper borrowings however, there were $947 million in outstanding letters of credit issued under the credit facility, resulting in $2,553 million of funds available under this revolving credit facility. Interest under this multicurrency facility is based upon LIBOR, NIBOR or EURIBOR plus 0.875% subject to a ratings-based grid, or the prime rate. The credit facility contains a financial covenant regarding maximum debt to capitalization and the Company was in compliance at December 31, 2013.

The Company also had $3,056 million of additional outstanding letters of credit at December 31, 2013, primarily in Norway, that are under various bilateral committed letter of credit facilities. Other letters of credit are issued as bid bonds, advanced payment bonds and performance bonds.

The fair value of the Company's Senior Notes are estimated using Level 2 inputs in the fair value hierarchy and is based on quoted prices for those or similar instruments. At December 31, 2013 and 2012, the fair value of the Company's unsecured Senior Notes approximated $2,896 million and $3,190 million, respectively. At December 31, 2013 and 2012, the carrying value of the Company's unsecured Senior Notes was $3,143 million and $3,142 million, respectively.

10. Employee Benefit Plans

We have benefit plans covering substantially all of our employees. Defined-contribution benefit plans cover most of the U.S. and Canadian employees, and benefits are based on years of service, a percentage of current earnings and matching of employee contributions. Employees in our Norwegian operations can elect to participate in a defined-contribution plan in lieu of a local defined benefit plan. For the years ended December 31, 2013, 2012 and 2011, expenses for defined-contribution plans were $96 million, $82 million, and $54 million, respectively, and all funding is current.

Certain retired or terminated employees of predecessor or acquired companies participate in a defined benefit plan in the United States. None of the participants in this plan are eligible to accrue benefits. In addition, 1,353 U.S. retirees and spouses participate in defined benefit health care plans of predecessor or acquired companies that provide postretirement medical and life insurance benefits. Active employees are ineligible to participate in any of these defined benefit plans. Our subsidiaries in the United Kingdom and Norway also have defined benefit pension plans covering virtually all of their employees.

As a result of the Robbins & Myers acquisition in February of 2013, the Company acquired four qualified, defined benefit, noncontributory pension plans for certain U.S. employees, an unfunded defined benefit pension plan for eligible employees in Germany, as well as two defined benefit, one contributory, pension plans in the U.K. The U.S. pension plans are closed to all new participants and there are no further benefit accruals under these plans. In addition, 230 U.S. employees covered by a collective bargaining agreement participate in a health care plan that provides postretirement medical benefits (which also covers approximately 400 retirees and dependents). The arrangements in Germany and the U.K. are all closed to new entrants, but benefits continue to accrue for current participants.

As a result of the Ameron acquisition in October of 2011, the Company acquired a qualified, defined benefit, noncontributory pension plan for certain U.S. employees as well as the obligation to provide defined retirement benefits to eligible employees in the Netherlands. The U.S. plan at December 31, 2011 was closed to new participants not covered by a collective bargaining agreement and ceased all benefit accruals under the plan with respect to employees that are not covered by a collective bargaining agreement. In addition, 232 U.S. employees covered by a collective bargaining agreement participate in defined benefit health care plans that provide postretirement medical benefits.

Net periodic benefit cost for our defined benefit plans aggregated $10 million, $10 million and $14 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The change in benefit obligation, plan assets and the funded status of the defined benefit pension plans in the United States, United Kingdom, Norway, Germany and the Netherlands and defined postretirement plans in the United States, using a measurement date of December 31, 2013 and December 31, 2012, is as follows (in millions):

	Pension benefits		Postretirement benefits	
At year end	2013	2012	2013	2012
Benefit obligation at beginning of year	$ 655	$ 556	$ 30	$ 35
Service cost	7	6	1	—
Interest cost	31	27	2	1
Actuarial loss (gain)	(10)	76	(12)	(2)
Benefits paid	(38)	(26)	(4)	(4)
Participants contributions	—	1	—	—
Exchange rate loss (gain)	7	12	—	—
Acquisitions	194	11	28	—
Curtailments	—	(8)	—	—
Benefit obligation at end of year	$ 846	$ 655	$ 45	$ 30
Fair value of plan assets at beginning of year	$ 517	$ 419	$ —	$ —
Actual return	72	49	—	—
Benefits paid	(38)	(26)	(4)	(4)
Company contributions	28	53	4	4
Participants contributions	—	1	—	—
Exchange rate gain (loss)	4	12	—	—
Acquisitions	123	9	—	—
Fair value of plan assets at end of year	$ 706	$ 517	$ —	$ —
Funded status	$(140)	$(138)	$ (45)	$ (30)
Accumulated benefit obligation at end of year	$ 811	$ 635		

Liabilities associated with the funded status of the defined benefit pension plans are included in the balances of accrued liabilities and other liabilities in the Consolidated Balance Sheet.

Defined Benefit Pension Plans

Assumed long-term rates of return on plan assets, discount rates and rates of compensation increases vary for the different plans according to the local economic conditions. The assumption rates used for benefit obligations are as follows:

	Years Ended December 31,	
	2013	2012
Discount rate:		
United States plan	4.65%	3.78%
International plans	3.50% - 4.40%	3.30% - 4.40%
Salary increase:		
United States plan	N/A	N/A
International plans	2.00% - 4.40%	2.00% - 3.87%

The assumption rates used for net periodic benefit costs are as follows:

	Years Ended December 31,		
	2013	2012	2011
Discount rate:			
United States plan	3.80%	4.58%	4.95%
International plans	3.46% - 4.40%	4.50% - 5.60%	5.25% - 5.65%
Salary increase:			
United States plan	N/A	N/A	N/A
International plans	2.00% - 3.53%	2.00% - 4.00%	2.00% - 4.33%
Expected return on assets:			
United States plan	6.30%	6.33%	5.50% - 6.50%
International plans	3.50% - 5.82%	4.50% - 6.51%	4.50% - 7.06%

In determining the overall expected long-term rate of return for plan assets, the Company takes into consideration the historical experience as well as future expectations of the asset mix involved. As different investments yield different returns, each asset category is reviewed individually and then weighted for significance in relation to the total portfolio.

The majority of our plans have projected benefit obligations in excess of plan assets.

The Company expects to pay future benefit amounts on its defined benefit plans of $47 million for each of the next five years and aggregate payments of $479 million.

Plan Assets

The Company and its investment advisers collaboratively reviewed market opportunities using historic and statistical data, as well as the actuarial valuation reports for the plans, to ensure that the levels of acceptable return and risk are well-defined and monitored. Currently, the Company’s management believes that there are no significant concentrations of risk associated with plan assets. Our pension investment strategy worldwide prohibits a direct investment in our own stock.

The following table sets forth by level, within the fair value hierarchy, the Plan's assets carried at fair value (in millions):

	Total	Fair Value Measurements Level 1	Level 2	Level 3
December 31, 2012:				
Equity securities	$204	$ —	$ 204	$ —
Bonds	139	—	139	—
Other (insurance contracts)	174	—	74	100
Total Fair Value Measurements	$517	$ —	$ 417	$ 100
December 31, 2013:				
Equity securities	$296	$ —	$ 296	$ —
Bonds	172	—	172	—
Other (insurance contracts)	238	—	131	107
Total Fair Value Measurements	$706	$ —	$ 599	$ 107

Level 3 inputs are unobservable (i.e., supported by little or no market activity). Level 3 inputs include management's own assumption about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). The following table sets forth a summary of changes in the fair value of the Plan's Level 3 assets (in millions):

	Level 3 Plan Assets
Balance at December 31, 2011	$ 77
Actual return on plan assets still held at reporting date	10
Purchases, sales and settlements	8
Currency translation adjustments	5
Balance at December 31, 2012	$ 100
Actual return on plan assets still held at reporting date	5
Purchases, sales and settlements	5
Currency translation adjustments	(3)
Balance at December 31, 2013	$ 107

11. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive income (loss) are as follows (in millions):

	Currency Translation Adjustments	Derivative Financial Instruments, Net of Tax	Defined Benefit Plans, Net of Tax	Total
Balance at December 31, 2010	$ 133	$ 6	$ (48)	$ 91
Accumulated other comprehensive income (loss) before reclassifications	(65)	(28)	20	(73)
Amounts reclassified from accumulated other comprehensive income (loss)	—	(35)	(6)	(41)
Balance at December 31, 2011	$ 68	$ (57)	$ (34)	$ (23)
Accumulated other comprehensive income (loss) before reclassifications	64	77	(29)	112
Amounts reclassified from accumulated other comprehensive income (loss)	—	22	(4)	18
Balance at December 31, 2012	$ 132	$ 42	$ (67)	$107
Accumulated other comprehensive income (loss) before reclassifications	(90)	(29)	48	(71)
Amounts reclassified from accumulated other comprehensive income (loss)	(25)	(8)	(7)	(40)
Balance at December 31, 2013	$ 17	$ 5	$ (26)	$ (4)

The components of amounts reclassified from accumulated other comprehensive income (loss) are as follows (in millions):

	Years Ended December 31,											
	2013				2012				2011			
	Currency Translation Adjustments	Derivative Financial Instruments	Defined Benefit Plans	Total	Currency Translation Adjustments	Derivative Financial Instruments	Defined Benefit Plans	Total	Currency Translation Adjustments	Derivative Financial Instruments	Defined Benefit Plans	Total
Revenue	$ —	$ (16)	$ —	$ (16)	$ —	$ 6	$ —	$ 6	$ —	$ (11)	$ —	$ (11)
Cost of revenue	—	6	—	6	—	26	—	26	—	(38)	—	(38)
Selling, general, and administrative	—	—	(8)	(8)	—	—	(6)	(6)	—	—	(7)	(7)
Other income (expense), net	(25)	—	—	(25)	—	—	—	—	—	—	—	—
Tax effect	—	2	1	3	—	(10)	2	(8)	—	14	1	15
	$ (25)	$ (8)	$ (7)	$ (40)	$ —	$ 22	$ (4)	$ 18	$ —	$ (35)	$ (6)	$ (41)

The Company's reporting currency is the U.S. dollar. A majority of the Company's international entities in which there is a substantial investment have the local currency as their functional currency. As a result, currency translation adjustments resulting from the process of translating the entities' financial statements into the reporting currency are reported in other comprehensive income or loss in accordance with ASC Topic 830 "Foreign Currency Matters" ("ASC Topic 830"). For the year ended December 31, 2013 a majority of these local currencies weakened against the U.S. dollar resulting in a net other comprehensive loss of $90 million upon the translation from local currencies to the U.S. dollar. Due to the sale of a foreign subsidiary during the second quarter of 2013, $25 million of currency translation gains were reclassified from accumulated other comprehensive income (loss) into other income (expense), net in the Consolidated Statements of Income. For the year ended December 31, 2012 a majority of these local currencies strengthened against the U.S. dollar resulting in a net other comprehensive income of $64 million upon the translation from local currencies to the U.S. dollar while for the year ended December 31, 2011 a majority of these local currencies weakened against the U.S. dollar resulting in a net other comprehensive loss of $65 million.

The effect of changes in the fair values of derivatives designated as cash flow hedges are accumulated in other comprehensive income (loss), net of tax, until the underlying transactions to which they are designed to hedge are realized. The movement in other comprehensive income (loss) from period to period will be the result of the combination of changes in fair value for open derivatives and the outflow of other comprehensive income (loss) related to cumulative changes in the fair value of derivatives that have settled in the current or prior periods. The accumulated effect was other comprehensive loss of $37 million (net of tax of $18 million) for the year ended December 31, 2013, other comprehensive income of $99 million (net of tax of $39 million) for the year ended December 31, 2012 and other comprehensive loss of $63 million (net of tax of $25 million) for the year ended December 31, 2011.

12. Commitments and Contingencies

We have received federal grand jury subpoenas and subsequent inquiries from governmental agencies requesting records related to our compliance with export trade laws and regulations. We have cooperated fully with agents from the U.S. Department of Justice (“DOJ”), the Department of Commerce Bureau of Industry and Security (“BIS”), the United States Department of Treasury, Office of Foreign Assets Control (“OFAC”), and U.S. Immigration and Customs Enforcement in responding to the inquiries. We have also cooperated with an informal inquiry from the Securities and Exchange Commission in connection with the inquiries previously made by the aforementioned federal agencies. We have conducted our own internal review of this matter. At the conclusion of our internal review in the fourth quarter of 2009, we identified possible areas of concern and discussed these areas of concern with the relevant agencies. We are currently negotiating a potential resolution with the agencies involved related to these matters. We currently anticipate that any administrative fine or penalty agreed to as part of a resolution would be within established accruals, and would not have a material effect on our financial position or results of operations. To the extent a resolution is not negotiated, we cannot predict the timing or effect that any resulting government actions may have on our financial position or results of operations.

In 2011, the Company acquired Ameron International Corporation (“Ameron”). On or about November 21, 2008, OFAC sent a Requirement to Furnish Information to Ameron. Ameron retained counsel and conducted an internal investigation. In 2009, Ameron, through its counsel, responded to OFAC. On or about January 21, 2011, OFAC issued an administrative subpoena to Ameron. OFAC and Ameron entered into Tolling Agreements. All of the conduct under review occurred before acquisition of Ameron by the Company. During the third quarter of 2013, the Company settled such matter with OFAC by paying an administrative fine in an amount that was not material to the Company.

On February 20, 2013, the Company acquired Robbins & Myers, Inc. (“R&M”). R&M was subject to an ongoing investigation by the DOJ and the BIS regarding potential export controls violations arising from certain shipments by R&M’s Belgian subsidiary to one customer in Iran, Sudan and Syria in 2005 and 2006. R&M has cooperated with the investigation and is currently negotiating a joint settlement with the DOJ and BIS. We currently anticipate that any administrative fine or criminal penalty agreed to as part of a resolution would be within established accruals, and would not have a material effect on our financial position or results of operations. To the extent a resolution is not negotiated, we cannot predict the timing or effect that any resulting government actions may have on our financial position or results of operations.

A gain of $102 million was recognized in the third quarter of 2013 related to a legal settlement. The gain was included in revenue of the Company’s Wellbore Technologies segment.

In addition, we are involved in various other claims, regulatory agency audits and pending or threatened legal actions involving a variety of matters. As of December 31, 2013, the Company recorded an immaterial amount for contingent liabilities representing all contingencies believed to be probable. The Company has also assessed the potential for additional losses above the amounts accrued as well as potential losses for matters that are not probable but are reasonably possible. The total potential loss on these matters cannot be determined; however, in our opinion, any ultimate liability, to the extent not otherwise provided for and except for the specific cases referred to above, will not materially affect our financial position, cash flow or results of operations. As it relates to the specific cases referred to above we currently anticipate that any administrative fine or penalty agreed to as part of a resolution would be within established accruals, and would not have a material effect on our financial position or results of operations. To the extent a resolution is not negotiated as anticipated, we cannot predict the timing or effect that any resulting government actions may have on our financial position, cash flow or results of operations. These estimated liabilities are based on the Company’s assessment of the nature of these matters, their progress toward resolution, the advice of legal counsel and outside experts as well as management’s intention and experience.

Our business is affected both directly and indirectly by governmental laws and regulations relating to the oilfield service industry in general, as well as by environmental and safety regulations that specifically apply to our business. Although we have not incurred material costs in connection with our compliance with such laws, there can be no assurance that other developments, such as new environmental laws, regulations and enforcement policies hereunder may not result in additional, presently unquantifiable, costs or liabilities to us.

The Company leases certain facilities and equipment under operating leases that expire at various dates through 2066. These leases generally contain renewal options and require the lessee to pay maintenance, insurance, taxes and other operating expenses in addition to the minimum annual rentals. Rental expense related to operating leases approximated $336 million, $281 million, and $234 million in 2013, 2012 and 2011, respectively.

Future minimum lease commitments under noncancellable operating leases with initial or remaining terms of one year or more at December 31, 2013, are payable as follows (in millions):

2014	$ 218
2015	169
2016	116
2017	87
2018	71
Thereafter	415
Total future lease commitments	$1,076

13. Common Stock

National Oilwell Varco has authorized 1 billion shares of $.01 par value common stock. The Company also has authorized 10 million shares of $.01 par value preferred stock, none of which is issued or outstanding.

Cash dividends aggregated $389 million and $209 million for the years ended December 31, 2013 and 2012, respectively. The declaration and payment of future dividends is at the discretion of the Company's Board of Directors and will be dependent upon the Company's results of operations, financial condition, capital requirements and other factors deemed relevant by the Company's Board of Directors.

Stock Options

Under the terms of National Oilwell Varco's Long-Term Incentive Plan, as amended during the second quarter of 2013, 39.5 million shares of common stock are authorized for the grant of options to officers, key employees, non-employee directors and other persons. Options granted under our stock option plan generally vest over a three-year period starting one year from the date of grant and expire ten years from the date of grant. The purchase price of options granted may not be less than the closing market price of National Oilwell Varco common stock on the date of grant. At December 31, 2013, approximately 14.5 million shares were available for future grants.

We also have inactive stock option plans that were acquired in connection with the acquisitions of Varco International, Inc. in 2005 and Grant Prideco in 2008. We converted the outstanding stock options under these plans to options to acquire our common stock and no further options are being issued under these plans. Stock option information summarized below includes amounts for the National Oilwell Varco Long-Term Incentive Plan and stock plans of acquired companies. Options outstanding at December 31, 2013 under the stock option plans have exercise prices between $9.14 and $84.58 per share, and expire at various dates from January 28, 2014 to February 10, 2023.

The following summarizes options activity:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price	Number of Shares	Average Exercise Price
Shares under option at beginning of year	9,473,482	$ 58.69	10,481,750	$ 47.20	11,039,544	$ 38.01
Granted	2,832,587	69.37	2,239,088	84.58	2,277,946	79.68
Cancelled	(303,417)	72.43	(228,137)	60.28	(241,174)	40.20
Exercised	(1,366,459)	77.44	(3,019,219)	82.26	(2,594,566)	36.84
Shares under option at end of year	10,636,193	$ 63.29	9,473,482	$ 58.69	10,481,750	$ 47.20
Exercisable at end of year	5,831,091	$ 53.46	4,823,331	$ 43.99	5,073,965	$ 38.47

The following summarizes information about stock options outstanding at December 31, 2013:

Range of Exercise Price	Weighted-Avg Remaining Contractual	Options Outstanding Shares	Options Outstanding Weighted Exercise	Options Exercisable Shares	Options Exercisable Weighted Exercise
$9.14—$45.00	4.36	3,201,686	$ 34.43	3,201,686	$ 34.43
$45.01—$70.00	8.17	3,361,420	67.84	622,464	61.32
$70.01—$84.58	7.63	4,073,087	82.21	2,006,941	81.39
Total	6.82	10,636,193	$ 63.29	5,831,091	$ 53.46

The weighted-average fair value of options granted during 2013, 2012 and 2011, was approximately $24.11, $30.01 and $29.52 per share, respectively, as determined using the Black-Scholes option-pricing model. The total intrinsic value of options exercised during 2013 and 2012, was $64 million and $120 million, respectively.

The determination of fair value of share-based payment awards on the date of grant using an option-pricing model is affected by our stock price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to, the expected stock price volatility over the term of the awards, and actual and projected employee stock option exercise activity. The use of the Black Scholes model requires the use of extensive actual employee exercise activity data and the use of a number of complex assumptions including expected volatility, risk-free interest rate, expected dividends and expected term.

	Years Ended December 31, 2013	2012	2011
Valuation Assumptions:			
Expected volatility	50.1%	51.7%	53.2%
Risk-free interest rate	0.9%	0.9%	2.1%
Expected dividends	$0.75	$0.57	$0.44
Expected term (in years)	3.4	3.2	3.1

The Company used the actual volatility for traded options for the past 10 years prior to option date as the expected volatility assumption required in the Black Scholes model.

The risk-free interest rate assumption is based upon observed interest rates appropriate for the term of our employee stock options. The dividend yield assumption is based on the history and expectation of dividend payouts. The estimated expected term is based on actual employee exercise activity for the past ten years.

As stock-based compensation expense recognized in the Consolidated Statement of Income in 2013 is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. ASC Topic 718 requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. Forfeitures were estimated based on historical experience.

The following summary presents information regarding outstanding options at December 31, 2013 and changes during 2013 with regard to options under all stock option plans:

	Shares	Weighted-Average Exercise Price	Weighted Remaining Contractual Term (years)	Average Aggregate Intrinsic Value
Outstanding at December 31, 2012	9,473,482	$ 58.69	6.86	$150,667,018
Granted	2,832,587	$ 69.37		
Exercised	(303,417)	$ 72.43		
Cancelled	(1,366,459)	$ 77.44		
Outstanding at December 31, 2013	10,636,193	$ 63.29	6.82	$183,849,267
Vested or expected to vest	10,466,014	$ 63.29	6.82	$180,907,679
Exercisable at December 31, 2013	5,831,091	$ 53.46	5.37	$155,892,094

At December 31, 2013, total unrecognized compensation cost related to nonvested stock options was $74 million. This cost is expected to be recognized over a weighted-average period of two years. The total fair value of stock options vested in 2013, 2012 and 2011 was approximately $64 million, $55 million and $54 million, respectively. Cash received from option exercises for 2013, 2012 and 2011 was $58 million, $113 million and $96 million, respectively. The actual tax benefit realized for the tax deductions from option exercises totaled $39 million, $42 million and $43 million for 2013, 2012 and 2011, respectively. Cash used to settle equity instruments granted under all share-based payment arrangements for 2013, 2012 and 2011 was not material for any period.

Restricted Shares

The Company issues restricted stock awards and restricted stock units to officers and key employees in addition to stock options. During the year ended December 31, 2013, the Company granted 540,194 shares of restricted stock and restricted stock units with a fair value of $69.33 per share and 16,702 shares of restricted stock with a fair value of $69.17 per share. In addition, the Company granted performance share awards to senior management employees with potential payouts varying from zero to 368,860 shares. The restricted stock and restricted stock units were granted February 15, 2013 and vest on the third anniversary of the date of grant, except for a special grant of 16,352 restricted stock units which vest on the second anniversary of the date of grant (subject to the satisfaction of a performance condition). On May 22, 2013, the 16,702 restricted stock awards, with a fair value of $69.17 per share, were granted to the non-employee members of the board of directors. These restricted stock awards vest in equal thirds over three years on the anniversary of the grant date. The performance share awards were granted on March 22, 2013 and can be earned based on performance against established goals over a three-year performance period. The performance share awards are divided into two equal, independent parts that are subject to two separate performance metrics: 50% with a TSR (total shareholder return) goal (the “TSR Award”) and 50% with an internal ROC (return on capital) goal (the “ROC Award”). During the first quarter of 2013, the Company concluded that the performance conditions relating to the performance-based restricted stock awards granted on February 16, 2010 were not met. As a result, the Company reversed $8 million in previously recognized stock-based compensation expense related to performance-based restricted stock awards that did not vest.

The following summary presents information regarding outstanding restricted shares:

	Years Ended December 31,					
	2013		2012		2011	
	Number of Units	Weighted-Average Grant Date Fair Value	Number of Units	Weighted-Average Grant Date Fair Value	Number of Units	Weighted-Average Grant Date Fair Value
Nonvested at beginning of year	1,336,666	$ 67.56	1,606,047	$ 44.21	1,765,837	$ 42.15
Granted	758,176	69.07	482,428	83.79	374,425	79.53
Vested	(340,218)	69.29	(406,844)	83.34	(496,642)	64.22
Cancelled	(239,534)	40.97	(344,965)	30.39	(37,573)	44.02
Nonvested at end of year	1,515,090	$ 73.73	1,336,666	$ 67.56	1,606,047	$ 44.21

The weighted-average grant day fair value of restricted stock awards and restricted stock units granted during the years ended 2013, 2012 and 2011 was $69.07, $83.79 and $79.53 per share, respectively. There were 340,218; 406,844 and 496,642 restricted stock awards that vested during 2013, 2012 and 2011, respectively. At December 31, 2013, there was approximately $54 million of unrecognized compensation cost related to nonvested restricted stock awards and restricted stock units, which is expected to be recognized over a weighted-average period of two years.

14. Income Taxes

The domestic and foreign components of income before income taxes were as follows (in millions):

	Years Ended December 31, 2013	2012	2011
Domestic	$1,362	$1,697	$1,193
Foreign	1,762	1,643	1,601
	$3,124	$3,340	$2,794

The components of the provision for income taxes consisted of (in millions):

	Years Ended December 31, 2013	2012	2011
Current:			
Federal	$ 632	$ 654	$ 450
State	55	44	34
Foreign	592	357	751
Total current income tax provision	1,279	1,055	1,235
Deferred:			
Federal	(157)	(147)	(23)
State	(12)	(1)	(3)
Foreign	(167)	58	(315)
Total deferred income tax provision	(336)	(90)	(341)
Total income tax provision	$ 943	$ 965	$ 894

The difference between the effective tax rate reflected in the provision for income taxes and the U.S. federal statutory rate was as follows (in millions):

	Years Ended December 31, 2013	2012	2011
Federal income tax at U.S. statutory rate	$1,093	$1,169	$ 978
Foreign income tax rate differential	(216)	(149)	(149)
State income tax, net of federal benefit	27	29	20
Nondeductible expenses	26	29	41
Tax benefit of manufacturing deduction	(33)	(29)	(37)
Foreign dividends, net of foreign tax credits	32	(116)	11
Change in deferred tax valuation allowance	40	80	(18)
Other	(26)	(48)	48
Total income tax provision	$ 943	$ 965	$ 894

Significant components of our deferred tax assets and liabilities were as follows (in millions):

	December 31, 2013	2012	2011
Deferred tax assets:			
Allowances and operating liabilities	$ 439	$ 368	$ 331
Net operating loss carryforwards	51	25	14
Postretirement benefits	49	54	14
Foreign tax credit carryforwards	300	259	106
Other	39	149	151
	878	855	616
Valuation allowance for deferred tax assets	(133)	(93)	(13)
Total deferred tax assets	745	762	603
Deferred tax liabilities:			
Tax over book depreciation	306	268	204
Intangible assets	1,757	1,448	1,398
Deferred income	285	314	226
Accrued U.S. tax on unremitted earnings	92	92	70
Other	164	208	168
Total deferred tax liabilities	2,604	2,330	2,066
Net deferred tax liability	$1,859	$1,568	$1,463

The balance of unrecognized tax benefits at December 31, 2013 and 2012 was $127 million and $128 million, respectively. Included in the change in the balance of unrecognized tax benefits for the period ended December 31, 2013 is a $1 million reduction in the balance of unrecognized tax benefits resulted from the lapse of applicable statutes of limitations in foreign jurisdictions. Of the net decrease of $1 million in the balance of unrecognized tax benefits, the entire $1 million was recorded as a decrease of income tax expense in the current year and is reflected in the “other” category in the income tax rate schedule above. These unrecognized tax benefits are included in the balance of other liabilities in the Consolidated Balance Sheet at December 31, 2013. If the $127 million of unrecognized tax benefits accrued at December 31, 2013 are ultimately realized, $54 million would be recorded as a reduction of income tax expense.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in millions):

	2013	2012	2011
Unrecognized tax benefit at beginning of year	$128	$131	$118
Additions based on tax positions related to the current year	—	2	9
Additions for tax positions of prior years	—	—	13
Reductions for lapse of applicable statutes of limitations	(1)	(5)	(9)
Unrecognized tax benefit at end of year	$127	$128	$131

The Company does not anticipate that the total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within 12 months of this reporting date.

To the extent penalties and interest would be assessed on any underpayment of income tax, such accrued amounts have been classified as a component of income tax expense in the financial statements consistent with the Company's policy. During the year ended December 31, 2013, the Company recorded as an increase of income tax expense a $0.4 million net increase of accrued interest and penalties related to uncertain tax positions. At December 31, 2013, the Company has accrued approximately $8 million of interest and penalties relating to unrecognized tax benefits. These interest and penalties are included in the balance of other liabilities in the Consolidated Balance Sheet at December 31, 2013.

The Company is subject to taxation in the United States, various states and foreign jurisdictions. The Company has significant operations in the United States, Norway, Canada, the United Kingdom, the Netherlands, France and Denmark. Tax years that remain subject to examination by major tax jurisdictions vary by legal entity, but are generally open in the U.S. for the tax years ending after 2007 and outside the U.S. for the tax years ending after 2006.

In the United States, the Company has $20 million of net operating loss carryforwards as of December 31, 2013, of which $4 million will expire in 2025, $13 million will expire in 2026, $1 million will expire in 2027, $1 million will expire in 2029 and $1 million will expire in 2030. The potential benefit of $7 million has been reduced by a $7 million valuation allowance. Future income tax payments will be reduced in the event the Company ultimately realizes the benefit of these net operating losses. If the Company ultimately realizes the benefit of these net operating loss carryforwards, the valuation allowance of $7 million would reduce future income tax expense.

Outside the United States, the Company has $170 million of net operating loss carryforwards as of December 31, 2013, of which $1 million will expire in 2014, $9 million will expire in 2015, $7 million will expire in 2016, $4 million will expire in 2017, $14 million will expire in 2018, $12 million will expire in 2020, $21 million will expire in 2021, $20 million will expire in 2022, $1 million will expire in 2023 and $81 million will carry forward indefinitely. The potential benefit of $44 million has been reduced by a $22 million valuation allowance. Future income tax payments will be reduced in the event the Company ultimately realizes the benefit of these net operating losses. If the Company ultimately realizes the benefit of these net operating loss carryforwards, the valuation allowance of $22 million would reduce future income tax expense.

Also in the United States, the Company has $300 million of excess foreign tax credits as of December 31, 2013, of which $73 million will expire in 2018, $71 million will expire in 2020, $142 million will expire in 2022, and $14 million will expire in 2023. These credits have been allotted a valuation allowance of $101 million and would be realized as a reduction of future income tax payments. In addition, there is a reserve for uncertain tax positions of $73 million against a portion of these credits.

During 2013, the Company recorded $371 million in net deferred tax liabilities with a corresponding increase in goodwill related to the 2013 acquisition of Robbins & Myers Inc.

Undistributed earnings of certain of the Company's foreign subsidiaries amounted to $6,045 million and $4,620 million at December 31, 2013 and 2012, respectively. Those earnings are considered to be permanently reinvested and no provision for U.S. federal and state income taxes has been made. Distribution of these earnings in the form of dividends or otherwise could result in U.S. federal taxes (subject to an adjustment for foreign tax credits) and withholding taxes payable in various foreign countries. Determination of the amount of unrecognized deferred U.S. income tax liability is not practical; however, unrecognized foreign tax credit carryforwards would be available to reduce some portion of the U.S. liability.

Because of the number of tax jurisdictions in which the Company operates, its effective tax rate can fluctuate as operations and the local country tax rates fluctuate. The Company is also subject to audits by federal, state and foreign jurisdictions which may result in proposed assessments. The Company's future tax provision will reflect any favorable or unfavorable adjustments to its estimated tax liabilities when resolved. The Company is unable to predict the outcome of these matters. However, the Company believes that none of these matters will have a material adverse effect on the results of operations or financial condition of the Company.

15. Business Segments and Geographic Areas

Effective April 1, 2014, the Company's operations were reorganized into four reportable segments: Rig Systems, Rig Aftermarket, Wellbore Technologies and Completion & Production Solutions. Within the four reporting segments, the Company has aggregated two business units under Rig Systems, one business unit under Rig Aftermarket, six business units under Wellbore Technologies and six business units under Completion & Production Solutions for a total of 15 business units. The Company has aggregated each of its business units in one of the four reporting segments based on the guidelines of ASC Topic 280, "Segment Reporting" ("ASC Topic 280").

Rig Systems

The Company's Rig Systems segment makes and supports the capital equipment and integrated systems needed to drill oil and gas wells on land and offshore. The segment designs, manufactures, and sells land rigs, offshore drilling equipment packages, including installation and commissioning services, and drilling rig components that mechanize and automate the rig process and functionality.

Equipment and technologies in Rig Systems include: substructures, derricks, and masts; cranes; pipe lifting, racking, rotating, and assembly systems; fluid transfer technologies, such as mud pumps; pressure control equipment, including blowout preventers; power transmission systems, including drives and generators; and rig instrumentation and control systems.

The Rig Systems segment primarily supports land and offshore drillers. Demand for Rig Systems products primarily depends on drilling contractors' and oil and gas companies' capital spending plans, specifically capital expenditures on rig construction and refurbishment.

Rig Aftermarket

The Company's Rig Aftermarket segment provides comprehensive aftermarket products and services to support land rigs and offshore rigs, and drilling rig components manufactured by the Rig Systems segment.

The segment provides spare parts, repair, and rentals as well as technical support, field service and first well support, field engineering, and customer training through a network of aftermarket service and repair facilities strategically located in major areas of drilling operations.

The Rig Aftermarket segment primarily supports land and offshore drillers. Demand for Rig Aftermarket products and services primarily depends on overall levels of oilfield drilling activity, which drives demand for spare parts, service, and repair for Rig System's large installed base of equipment; and secondarily on drilling contractors' and oil and gas companies' capital spending plans, specifically capital expenditures on rig refurbishment and re-certification.

Wellbore Technologies

The Company's Wellbore Technologies segment designs, manufactures, rents, and sells a variety of equipment and technologies used to perform drilling operations, and offers services that optimize their performance, including: solids control and waste management equipment and services, drilling fluids, premium drill pipe, wired pipe, tubular inspection and coating services, instrumentation, downhole tools, and drill bits.

The Wellbore Technologies segment focuses on oil and gas companies and supports drilling contractors, oilfield service companies, and oilfield rental companies. Demand for Wellbore Technologies products and services primarily depends on the level of oilfield drilling activity by oil and gas companies, drilling contractors, and oilfield service companies.

Completion & Production Solutions

The Company's Completion & Production Solutions segment integrates technologies for well completions and oil and gas production. The segment designs, manufactures, and sells equipment and technologies needed for hydraulic fracture stimulation, including pressure pumping trucks and pumps, blenders, sanders, hydration units, injection units, flowline, manifolds and wellheads; well intervention, including coiled tubing units, coiled tubing, and wireline units and tools; onshore production, including composite pipe, surface transfer and progressive cavity pumps, and artificial lift systems; and offshore production, including floating production systems and subsea production technologies.

The Completion & Production Solutions segment primarily supports service companies and oil and gas companies. Demand for Completion & Production Solutions products depends on the level of oilfield completions and workover activity by oilfield service companies and drilling contractors and capital spending plans by oil and gas companies and oilfield service companies.

The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies of the Company. The Company evaluates performance of each reportable segment based upon its operating income, excluding non-recurring items.

The Company had revenues of 11%, 11% and 13% of total revenue from one of its customers for the years ended December 31, 2013, 2012, and 2011, respectively. This customer, Samsung Heavy Industries, is a shipyard acting as a general contractor for its customers, who are drillship owners and drilling contractors. This shipyard's customers have specified that the Company's drilling equipment be installed on their drillships and have required the shipyard to issue contracts to the Company.

Geographic Areas:

The following table presents consolidated revenues by country based on sales destination of the use of the products or services (in millions):

	Years Ended December 31,		
	2013	2012	2011
United States	$ 5,140	$ 6,040	$ 4,532
South Korea	3,219	3,121	2,257
Singapore	1,850	1,118	721
Norway	1,102	736	689
China	1,007	533	430
Brazil	811	503	397
United Kingdom	705	523	465
Canada	625	728	608
Other Countries	4,762	3,892	3,376
Total	$19,221	$17,194	$13,475

The following table presents long-lived assets by country based on the location (in millions):

	December 31,	
	2013	2012
United States	$1,830	$1,606
Brazil	270	162
United Kingdom	200	173
Denmark	166	174
Canada	123	131
South Korea	115	112
Mexico	101	87
Singapore	94	93
Other Countries	509	407
Total	$3,408	$2,945

Business Segments:

	Rig Systems	Rig Aftermarket	Wellbore Technologies	Completion & Production Solutions	Eliminations(1)	Discontinued Operations	Total
December 31, 2013:							
Revenues	$8,450	$ 2,692	$ 5,211	$ 4,309	$ (1,441)	$ —	$19,221
Operating profit	1,594	729	915	613	(652)	—	3,199
Capital expenditures	61	24	226	212	91	—	614
Depreciation and amortization	82	26	420	210	—	—	738
Goodwill	1,279	906	4,425	2,106	—	333	9,049
Total assets	7,654	2,475	11,862	7,287	3,351	2,183	34,812
December 31, 2012:							
Revenues	$7,077	$ 2,138	$ 5,184	$ 3,994	$ (1,199)	$ —	$17,194
Operating profit	1,685	594	983	684	(557)	—	3,389
Capital expenditures	81	13	247	169	59	—	569
Depreciation and amortization	64	18	389	145	—	—	616
Goodwill	1,097	649	3,769	1,314	—	343	7,172
Total assets	6,563	1,930	11,032	6,192	3,394	2,373	31,484
December 31, 2011:							
Revenues	$5,686	$ 1,876	$ 4,455	$ 2,483	$ (1,025)	$ —	$13,475
Operating profit	1,562	528	726	456	(463)	—	2,809
Capital expenditures	70	10	245	103	51	—	479
Depreciation and amortization	61	14	381	93	—	—	549
Goodwill	943	556	3,683	917	—	52	6,151
Total assets	4,743	1,569	10,799	4,020	3,555	829	25,515

(1) Sales from one segment to another generally are priced at estimated equivalent commercial selling prices; however, segments originating an external sale are credited with the full profit to the company. Eliminations include intercompany transactions conducted between the four reporting segments that are eliminated in consolidation. Intercompany transactions within each reporting segment are eliminated within each reporting segment. Also included in the eliminations column are capital expenditures and total assets related to corporate. Corporate assets consist primarily of cash and fixed assets.

16. Quarterly Financial Data (Unaudited)

Summarized quarterly results, were as follows (in millions, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 31, 2013				
Revenue	$4,376	$4,680	$4,863	$5,302
Gross profit	1,167	1,173	1,360	1,404
Income from continuing operations	461	494	598	627
Income from discontinued operations	41	37	38	31
Net income attributable to Company	502	531	636	658
Per share data:				
Basic:				
Income from continuing operations	1.08	1.16	1.40	1.47
Income from discontinued operations	0.10	0.09	0.09	0.07
Net income attributable to Company	1.18	1.25	1.49	1.54
Diluted:				
Income from continuing operations	1.07	1.15	1.40	1.47
Income from discontinued operations	0.10	0.09	0.09	0.07
Net income attributable to Company	1.17	1.24	1.49	1.53
Cash dividends per share	0.13	0.26	0.26	0.26
Year ended December 31, 2012				
Revenue	$3,968	$4,206	$4,307	$4,713
Gross profit	1,214	1,228	1,247	1,354
Income from continuing operations	583	579	584	637
Income from discontinued operations	23	26	28	31
Net income attributable to Company	606	605	612	668
Per share data:				
Basic:				
Income from continuing operations	1.37	1.37	1.38	1.50
Income from discontinued operations	0.06	0.05	0.06	0.07
Net income attributable to Company	1.43	1.42	1.44	1.57
Diluted:				
Income from continuing operations	1.36	1.35	1.36	1.49
Income from discontinued operations	0.06	0.06	0.06	0.07
Net income attributable to Company	1.42	1.42	1.43	1.56
Cash dividends per share	0.12	0.12	0.12	0.13

17. Spin-off of distribution business

On May 30, 2014, the Company completed the previously announced spin-off (the “spin-off”) of its distribution business into an independent public company named NOW Inc., which trades on the New York Stock Exchange under the symbol “DNOW”. After the close of the New York Stock Exchange on May 30, 2014, the stockholders of record as of May 22, 2014 (the “Record Date”) received one share of NOW Inc. common stock for every four shares of NOV common stock held on the Record Date. No fractional shares of NOW Inc. common stock were distributed. Instead, the transfer agent aggregated any fractional shares into whole shares, sold those whole shares in the open market at prevailing rates and distributed the net cash proceeds, after deducting any taxes required to be withheld and any amount equal to all brokerage charges and commissions, pro rata to each holder who would otherwise have been entitled to receive fractional shares in the distribution.

In order to effect the spin-off and govern its relationship with NOW after the spin-off, the Company entered into a Separation and Distribution Agreement, a Tax Matters Agreement, an Employee Matters Agreement, a Transition Services Agreement, a Master Distributor Agreement, and a Master Services Agreement. The Separation and Distribution Agreement governs the terms of the separation of the distribution business from NOV’s other businesses. Generally, the Separation and Distribution Agreement includes agreements between NOW and NOV relating to the restructuring steps needed to be taken to complete the separation, including the assets, equity interests and rights to be transferred, liabilities to be assumed, contracts to be assigned and related matters. The Separation and Distribution Agreement also governs the treatment of aspects relating to indemnification, insurance, litigation responsibility, confidentiality, management, intellectual property (including trademarks) and cooperation.

The Tax Matters Agreement governs respective rights, responsibilities and obligations of NOV and NOW with respect to deficiencies and refunds, if any, of federal, state, local, and foreign taxes for periods before and after the distribution, as well as taxes attributable to the separation and distribution, and related matters such as the filing of tax returns and the conduct of IRS and other audits. In addition, the Tax Matters Agreement imposes certain restrictions on NOW and its subsidiaries (including restrictions on share issuances, business combinations, sales of assets and similar transactions) that are designed to preserve the generally tax-free status of the separation and distribution.

The Employee Matters Agreement governs the compensation and employee benefit obligations with respect to the current and former employees of NOV and NOW and generally allocates liabilities and responsibilities relating to employee compensation and benefit plans and programs. The Employee Matters Agreement provides for the treatment of outstanding NOV equity awards. The Employee Matters Agreement also sets forth the general principles relating to employee matters, including with respect to the assignment of employees and the transfer of employees from us to NOW, the assumption and retention of liabilities and related assets, expense reimbursements, workers’ compensation, leaves of absence, the provision of comparable benefits, employee service credits, the sharing of employee information and the duplication or acceleration of benefits.

The Transition Services Agreement sets forth the terms on which NOV will provide to NOW, and NOW will provide to NOV, on a temporary basis, certain services or functions that the companies historically have shared. Transition services may include administrative, payroll, human resources, data processing, environmental health and safety, financial audit support, financial transaction support, legal support services, IT and network infrastructure systems and various other support and corporate services. The Transition Services Agreement provides for the provision of specified transition services generally for a period of up to 18 months.

The Master Distributor Agreement provides that NOW will act as a distributor of certain of NOV's products. Under the Master Supply Agreement, NOW will supply products and provide solutions, including supply chain management solutions, to NOV.

The following table presents the carrying value of assets and liabilities of NOW (in millions):

	December 31, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	$ 101	$ 138
Receivables, net	661	692
Inventories, net	850	1,015
Deferred income taxes	21	18
Prepaid and other current assets	29	19
Total current assets of discontinued operations	1,662	1,882
Property, plant and equipment, net	102	61
Deferred income taxes	15	11
Goodwill	333	343
Intangibles, net	68	74
Other assets	3	2
Total assets of discontinued operations	$2,183	$2,373
Current liabilities:		
Accounts payable	$ 264	$ 272
Accrued liabilities	99	113
Accrued income taxes	—	6
Total current liabilities of discontinued operations	363	391
Deferred income taxes	16	9
Other liabilities	2	2
Total liabilities of discontinued operations	$ 381	$ 402

The following table presents selected financial information regarding the results of operations of our distribution business, which is reported as discontinued operations (in millions):

	Years Ended December 31,		
	2013	2012	2011
Revenue from discontinued operations	$4,296	$3,414	$1,641
Income from discontinued operations before income taxes	222	165	128
Income tax expense	75	57	43
Income from discontinued operations	$ 147	$ 108	$ 85

Prior to the spin-off, sales to NOW were $499 million, $450 million and $382 million for the years ended December 31, 2013, 2012 and 2011, respectively. Prior to the spin-off, purchases from NOW $149 million, $117 million and $76 million for the years ended December 31, 2013, 2012 and 2011, respectively. Prior to May 30, 2014, the spin-off date, revenue and related cost of revenue were eliminated in consolidation between NOV and NOW. Beginning May 31, 2014, this revenue and cost of revenue represent third-party transactions with NOW.

SCHEDULE II
NATIONAL OILWELL VARCO, INC.
VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2013, 2012 and 2011
(in millions)

	Balance beginning of year	Additions (Deductions) charged to costs and expenses	Charge off's and other	Balance end of year
Allowance for doubtful accounts:				
2013	$ 120	$ 32	$ (20)	$ 132
2012	107	6	7	120
2011	107	9	(9)	107
Allowance for excess and obsolete inventories:				
2013	$ 338	$ 89	$ (31)	$ 396
2012	281	99	(42)	338
2011	270	70	(59)	281
Valuation allowance for deferred tax assets:				
2013	$ 93	$ 40	$ —	$ 133
2012	13	80	—	93
2011	9	4	—	13
Warranty reserve:				
2013	$ 194	$ 101	$ (67)	$ 228
2012	211	51	(68)	194
2011	215	40	(44)	211