



Human Energy[®]

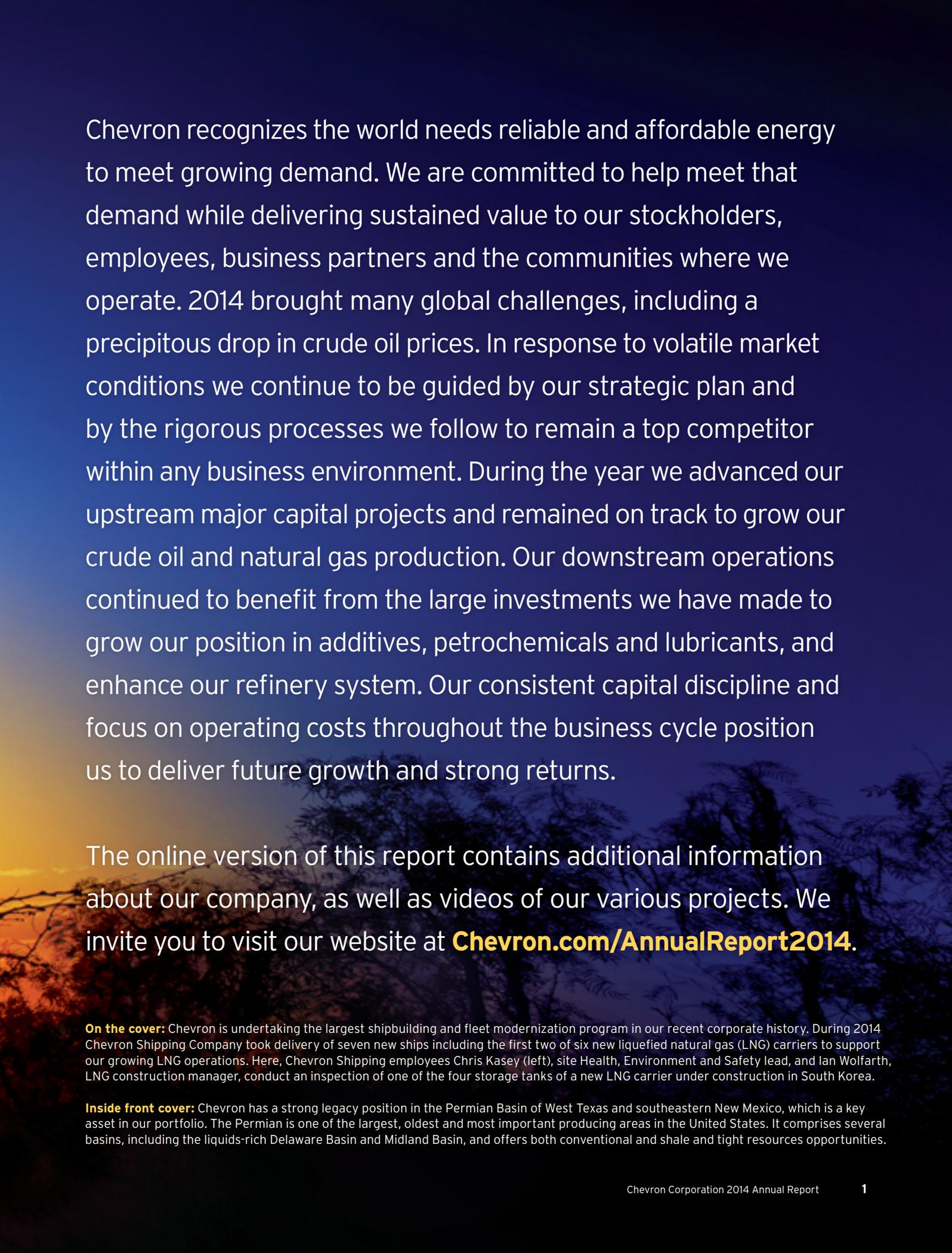
2014 Annual Report



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Chevron recognizes the world needs reliable and affordable energy to meet growing demand. We are committed to help meet that demand while delivering sustained value to our stockholders, employees, business partners and the communities where we operate. 2014 brought many global challenges, including a precipitous drop in crude oil prices. In response to volatile market conditions we continue to be guided by our strategic plan and by the rigorous processes we follow to remain a top competitor within any business environment. During the year we advanced our upstream major capital projects and remained on track to grow our crude oil and natural gas production. Our downstream operations continued to benefit from the large investments we have made to grow our position in additives, petrochemicals and lubricants, and enhance our refinery system. Our consistent capital discipline and focus on operating costs throughout the business cycle position us to deliver future growth and strong returns.

The online version of this report contains additional information about our company, as well as videos of our various projects. We invite you to visit our website at Chevron.com/AnnualReport2014.

On the cover: Chevron is undertaking the largest shipbuilding and fleet modernization program in our recent corporate history. During 2014 Chevron Shipping Company took delivery of seven new ships including the first two of six new liquefied natural gas (LNG) carriers to support our growing LNG operations. Here, Chevron Shipping employees Chris Kasey (left), site Health, Environment and Safety lead, and Ian Wolfarth, LNG construction manager, conduct an inspection of one of the four storage tanks of a new LNG carrier under construction in South Korea.

Inside front cover: Chevron has a strong legacy position in the Permian Basin of West Texas and southeastern New Mexico, which is a key asset in our portfolio. The Permian is one of the largest, oldest and most important producing areas in the United States. It comprises several basins, including the liquids-rich Delaware Basin and Midland Basin, and offers both conventional and shale and tight resources opportunities.

To Our Stockholders



For Chevron 2014 was a year of moving forward our strong queue of projects. Even as we experienced a 50 percent drop in the price of oil in the second half of the year, we maintained our focus on providing affordable and reliable energy, safely and responsibly, to the benefit of our stakeholders.

Financially we had a solid year as reflected in our net income of \$19.2 billion on sales and other operating revenues of \$200.5 billion. We achieved a 10.9 percent return on capital employed. 2014 represented the 27th consecutive year of annual dividend payout increases, underlining that our commitment to the dividend is our highest financial priority. In 2014 we launched our three-year \$10 billion divestment program, obtaining \$5.7 billion in asset sales during the first year. Finally, although market returns were challenged in 2014 our annualized total stockholder returns of 11.5 and 11.4 percent over the past five- and 10-year periods, respectively, continued to lead our peer group.

In the upstream we ranked No. 1 in earnings per barrel relative to our peers for the fifth straight year. We are targeting production of 3.1 million barrels of oil-equivalent per day in 2017, a 20 percent increase from 2014, which is a larger growth rate than that projected for our large competitors. In early December Jack/St. Malo, one of our deepwater U.S. Gulf of Mexico projects, delivered first oil on time and within budget. In 2015 we'll

also see additional production from ramp-ups at Tubular Bells in the Gulf of Mexico, the Bibiyana expansion in Bangladesh and our Escravos gas-to-liquids facility in Nigeria, all of which started up in 2014. We also expect the startup in 2015 of our Gorgon liquefied natural gas project offshore Western Australia, and we will ramp up production from our Permian Basin assets in the United States.

In exploration we're positioning ourselves for growth. We had a successful year in 2014, including two significant Gulf of Mexico discoveries in the deep water – Guadalupe and Anchor – as well as promising discoveries in Australia, Canada and the Permian Basin.

We enter 2015 with the financial strength to meet the challenges of a volatile crude oil price environment. We have significant efforts underway to manage to a lower cost structure and capital spend rate.

In downstream and chemicals we ranked No. 1 in earnings per barrel relative to our peers. We are benefiting from improved reliability and targeted growth efforts. We made reliability investments at several refineries, including in El Segundo, California, and Salt Lake City, Utah. We started up the Pascagoula, Mississippi, base oil facility this year, making Chevron the world's largest premium base oil producer. Oronite completed a major expansion in Singapore, which, when combined with earlier growth initiatives, doubled the plant's original additives production capacity. Chevron Phillips Chemical, our joint venture, started up a new 1-hexene plant in Texas, where it also broke ground on a new ethane cracker and two polyethylene facilities.

We enter 2015 with the financial strength to meet the challenges of a volatile crude oil price environment. We have significant efforts underway to manage to a lower cost structure and capital spend rate. We announced a 2015 capital and exploratory budget of \$35 billion. The 2015 budget is 13 percent lower than total investments for 2014, reflecting our focus on being more selective with our investments in the current lower-price environment.

We remain committed to delivering world-class safety, operational and environmental performance in our businesses. In 2014 we delivered our best overall year in personal safety, as measured by recordable injuries and injuries requiring time away

from work, and in process safety as measured by loss of containment incidents. We also had record lows in our process fires, petroleum spill volume and motor vehicle crash rate. In the last decade our Days Away From Work Rate has declined by 83 percent, our Total Recordable Incident Rate has improved by 55 percent, and our Motor Vehicle Crash Rate has declined by 50 percent.

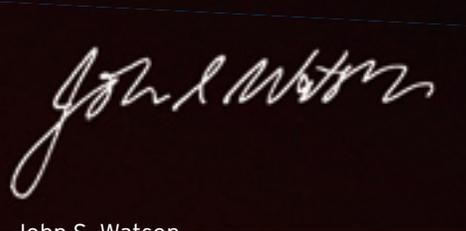
We are just as determined to maintain our strong social performance, recognizing that healthy businesses require healthy communities. We will continue to invest in projects and local goods and services, create jobs, and generate revenues for the communities in which we work. Beyond our direct business investments and

taxes, we will continue strategic social investments. Over the past nine years we have contributed approximately \$1.7 billion in social investments, with a special focus on three core areas – health, education and economic development – to develop skilled workers, improve access to health care, and boost local and regional economies. More details about these investments are available in the *2014 Corporate Responsibility Report*.

As always, The Chevron Way provides a roadmap for how we conduct our business, setting our vision to be *the* global energy company most admired for its people, partnership and performance. It establishes the values by which we deliver our results, including acting with integrity, promoting diversity, and protecting people and the environment. By following The Chevron Way we will continue to create enduring value for the communities where we operate and for our stockholders.

The progress we made this past year is due to the hard work and determination of our workforce. All of us at Chevron are committed to excellence in everything we do. The end result is the strong performance we delivered in 2014.

Thank you for investing in Chevron.



John S. Watson
Chairman of the Board and
Chief Executive Officer
February 20, 2015

Chevron Financial Highlights

Millions of dollars, except per-share amounts	2014	2013	% Change
Net income attributable to Chevron Corporation	\$ 19,241	\$ 21,423	(10.2)%
Sales and other operating revenues	\$ 200,494	\$ 220,156	(8.9)%
Noncontrolling interests income	\$ 69	\$ 174	(60.3)%
Interest expense (after tax)	\$ –	\$ –	0.0 %
Capital and exploratory expenditures*	\$ 40,316	\$ 41,877	(3.7)%
Total assets at year-end	\$ 266,026	\$ 253,753	4.8 %
Total debt and capital lease obligations at year-end	\$ 27,818	\$ 20,431	36.2 %
Noncontrolling interests	\$ 1,163	\$ 1,314	(11.5)%
Chevron Corporation stockholders' equity at year-end	\$ 155,028	\$ 149,113	4.0 %
Cash provided by operating activities	\$ 31,475	\$ 35,002	(10.1)%
Common shares outstanding at year-end (Thousands)	1,865,481	1,899,435	(1.8)%
Per-share data			
Net income attributable to Chevron Corporation – diluted	\$ 10.14	\$ 11.09	(8.6)%
Cash dividends	\$ 4.21	\$ 3.90	7.9 %
Chevron Corporation stockholders' equity	\$ 83.10	\$ 78.50	5.9 %
Common stock price at year-end	\$ 112.18	\$ 124.91	(10.2)%
Total debt to total debt-plus-equity ratio	15.2%	12.1%	
Return on average Chevron Corporation stockholders' equity	12.7%	15.0%	
Return on capital employed (ROCE)	10.9%	13.5%	

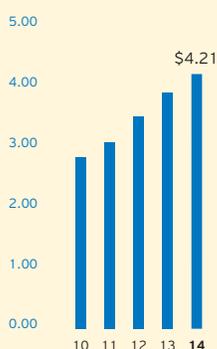
*Includes equity in affiliates

Net Income Attributable to Chevron Corporation
Billions of dollars



The decrease in 2014 was due to lower earnings in upstream as a result of lower crude oil margins and higher depreciation expense, partially offset by higher earnings in downstream and higher gains on asset sales.

Annual Cash Dividends
Dollars per share



The company's annual dividend increased for the 27th consecutive year.

Chevron Year-End Common Stock Price
Dollars per share



The company's stock price declined 10.2 percent in 2014.

Return on Capital Employed
Percent



Chevron's return on capital employed declined to 10.9 percent on lower earnings and higher capital employed.

Chevron Operating Highlights¹

	2014	2013	% Change
Net production of crude oil, condensate and natural gas liquids (Thousands of barrels per day)	1,709	1,731	(1.3)%
Net production of natural gas (Millions of cubic feet per day)	5,167	5,192	(0.5)%
Total net oil-equivalent production (Thousands of oil-equivalent barrels per day)	2,571	2,597	(1.0)%
Refinery input (Thousands of barrels per day)	1,690	1,638	3.2%
Sales of refined products (Thousands of barrels per day)	2,711	2,711	(0.0)%
Net proved reserves of crude oil, condensate and natural gas liquids ² (Millions of barrels)			
– Consolidated companies	4,285	4,303	(0.4)%
– Affiliated companies	1,964	2,042	(3.8)%
Net proved reserves of natural gas ² (Billions of cubic feet)			
– Consolidated companies	25,707	25,670	0.1%
– Affiliated companies	3,409	3,476	(1.9)%
Net proved oil-equivalent reserves ² (Millions of barrels)			
– Consolidated companies	8,570	8,582	(0.1)%
– Affiliated companies	2,532	2,621	(3.4)%
Number of employees at year-end ³	61,456	61,345	0.2%

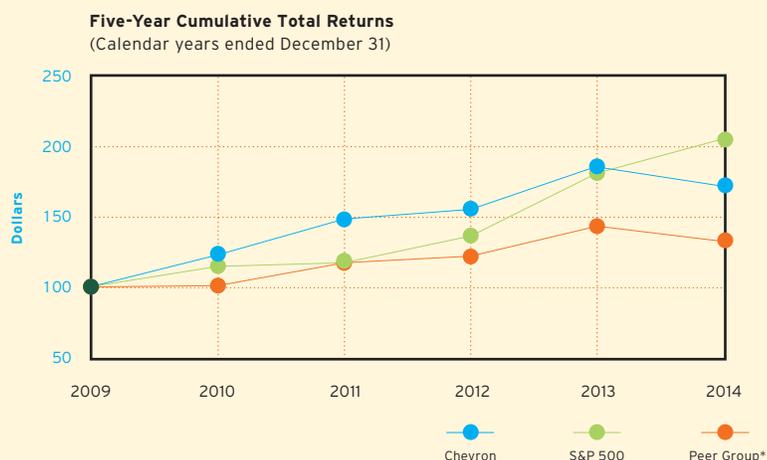
¹ Includes equity in affiliates, except number of employees

² At the end of the year

³ Excludes service station personnel

Performance Graph

The stock performance graph at right shows how an initial investment of \$100 in Chevron stock would have compared with an equal investment in the S&P 500 Index or the Competitor Peer Group. The comparison covers a five-year period beginning December 31, 2009, and ending December 31, 2014, and for the peer group is weighted by market capitalization as of the beginning of each year. It includes the reinvestment of all dividends that an investor would be entitled to receive and is adjusted for stock splits. The interim measurement points show the value of \$100 invested on December 31, 2009, as of the end of each year between 2010 and 2014.



	2009	2010	2011	2012	2013	2014
Chevron	100.00	122.88	147.79	155.18	185.04	172.24
S&P 500	100.00	115.05	117.49	136.27	180.43	205.13
Peer Group*	100.00	100.93	116.88	121.90	143.25	133.13

*Peer Group: BP p.l.c.-ADS, ExxonMobil, Royal Dutch Shell p.l.c.-ADS, Total S.A.-ADS

Chevron at a Glance

Chevron is one of the world's leading integrated energy companies. Our success is driven by our people and their commitment to getting results the right way – by operating responsibly, executing with excellence, applying innovative technologies and capturing new opportunities for profitable growth. We are involved in virtually every facet of the energy industry. We explore for, produce and transport crude oil and natural gas; refine, market and distribute transportation fuels and lubricants; manufacture and sell petrochemicals and additives; generate power and produce geothermal energy; and develop and deploy technologies that improve the energy efficiency of our operations worldwide.



Upstream	<p>Strategy: Grow profitably in core areas and build new legacy positions.</p>	<p>Upstream explores for and produces crude oil and natural gas. At the end of 2014 worldwide net oil-equivalent proved reserves for consolidated and affiliated companies were 11.1 billion barrels. During 2014 net oil-equivalent production averaged 2.6 million barrels per day. Top producing areas include Angola, Australia, Bangladesh, Canada, Indonesia, Kazakhstan, Nigeria, the Partitioned Zone between Kuwait and Saudi Arabia, Thailand, the United States and Venezuela. Major conventional exploration areas include the deepwater U.S. Gulf of Mexico, the offshore areas of Australia and western Africa, and the Kurdistan Region of Iraq. Key exploration areas for unconventional shale and tight resources are Argentina, Canada and the United States.</p>
Downstream and Chemicals	<p>Strategy: Deliver competitive returns and grow earnings across the value chain.</p>	<p>Downstream and Chemicals includes refining, fuels and lubricants marketing, and petrochemicals and additives manufacturing and marketing. In 2014 we processed 1.7 million barrels of crude oil per day and averaged 2.7 million barrels per day of refined product sales worldwide. Our most significant areas of refinery operations are the west coast of North America, the U.S. Gulf Coast, Singapore, Thailand, South Korea and South Africa. We hold interests in 13 refineries and market transportation fuels and lubricants under the Chevron, Texaco and Caltex brands. Products are sold through a network of 16,377 retail stations, including those of affiliated companies. Our chemicals business includes Chevron Phillips Chemical Company LLC, a 50 percent-owned affiliate that is one of the world's leading manufacturers of commodity petrochemicals, and Chevron Oronite Company LLC, which develops, manufactures and markets quality additives that improve the performance of fuels and lubricants.</p>
Gas and Midstream	<p>Strategy: Apply commercial and functional excellence to enable the success of Upstream and Downstream and Chemicals.</p>	<p>Gas and Midstream provides services that link Upstream and Downstream and Chemicals to the market. This includes commercializing our equity gas resource base and maximizing the value of the company's equity natural gas, crude oil, natural gas liquids and refined products. It has global operations with major centers in Houston; London; Singapore; and San Ramon, California.</p>
Technology	<p>Strategy: Differentiate performance through technology.</p>	<p>Our three technology companies – Energy Technology, Technology Ventures and Information Technology – are focused on enhancing business value in every aspect of our operations. We have established major technology centers in Australia, the United Kingdom and the United States. Together they provide strategic research, technology development, technical and computing infrastructure services, and data protection to our global businesses.</p>
Renewable Energy and Energy Efficiency	<p>Strategy: Invest in profitable renewable energy and energy efficiency solutions.</p>	<p>We are one of the world's leading producers of geothermal energy, supplying abundant, reliable energy to millions of people in Indonesia and the Philippines. We also are investing in energy efficiency technologies to improve the performance of our operations worldwide.</p>
Operational Excellence		<p>We define operational excellence as the systematic management of process safety, personal safety and health, the environment, reliability, and energy efficiency. Safety is our highest priority. We are committed to attaining superior performance in operational excellence and believe our goal of zero incidents is attainable.</p>

Photo Left: With the 2014 startup of the 25,000-barrel-per-day premium base oil facility at the company's Pascagoula, Mississippi, refinery, Chevron became the worldwide leader in premium base oil production. Premium base oil is used in more advanced lubricant formulations to meet increasing global standards for emissions and fuel efficiency.

Glossary of Energy and Financial Terms

Energy Terms

Additives Specialty chemicals incorporated into fuels and lubricants that enhance the performance of the finished products.

Barrels of oil-equivalent (BOE) A unit of measure to quantify crude oil, natural gas liquids and natural gas amounts using the same basis. Natural gas volumes are converted to barrels on the basis of energy content. See *oil-equivalent gas* and *production*.

Biofuel Any fuel that is derived from biomass – recently living organisms or their metabolic byproducts – from sources such as farming, forestry, and biodegradable industrial and municipal waste. See *renewables*.

Condensate Hydrocarbons that are in a gaseous state at reservoir conditions but condense into liquid as they travel up the wellbore and reach surface conditions.

Development Drilling, construction and related activities following discovery that are necessary to begin production and transportation of crude oil and natural gas.

Enhanced recovery Techniques used to increase or prolong production from crude oil and natural gas reservoirs.

Entitlement effects The impact on Chevron's share of net production and net proved reserves due to changes in crude oil and natural gas prices, and spending levels, between periods. Under production-sharing contracts (PSCs) and variable-royalty provisions of certain agreements, price and spend variability can increase or decrease royalty burdens and/or volumes attributable to the company. For example, at higher prices, fewer volumes are required for Chevron to recover its costs under certain PSCs. Also under certain PSCs, Chevron's share of future profit oil and/or gas is reduced once specified contractual thresholds are met, such as a cumulative return on investment.

Exploration Searching for crude oil and/or natural gas by utilizing geologic and topographical studies, geophysical and seismic surveys, and drilling of wells.

Gas-to-liquids (GTL) A process that converts natural gas into high-quality liquid transportation fuels and other products.

Greenhouse gases Gases that trap heat in Earth's atmosphere (e.g., water vapor, ozone, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride).

Integrated energy company A company engaged in all aspects of the energy industry, including exploring for and producing crude oil and natural gas; refining, marketing and transporting crude oil, natural gas and refined products; manufacturing and distributing petrochemicals; and generating power.

Liquefied natural gas (LNG) Natural gas that is liquefied under extremely cold temperatures to facilitate storage or transportation in specially designed vessels.

Natural gas liquids (NGLs) Separated from natural gas, these include ethane, propane, butane and natural gasoline.

Oil-equivalent gas (OEG) The volume of natural gas needed to generate the equivalent amount of heat as a barrel of crude oil. Approximately 6,000 cubic feet of natural gas is equivalent to one barrel of crude oil.

Oil sands Naturally occurring mixture of bitumen (a heavy, viscous form of crude oil), water, sand and clay. Using hydroprocessing technology, bitumen can be refined to yield *synthetic oil*.

Petrochemicals Compounds derived from petroleum. These include aromatics, which are used to make plastics, adhesives, synthetic fibers and household detergents; and olefins, which are used to make packaging, plastic pipes, tires, batteries, household detergents and synthetic motor oils.

Production *Total production* refers to all the crude oil (including *synthetic oil*), NGLs and natural gas produced from a property. *Net production* is the company's share of *total production* after deducting both royalties paid to landowners and a government's agreed-upon share of production under a *production-sharing contract*. *Liquids production* refers to crude oil, condensate, NGLs and synthetic oil volumes. *Oil-equivalent production* is the sum of the barrels of *liquids* and the oil-equivalent barrels of natural gas produced. See *barrels of oil-equivalent* and *oil-equivalent gas*.

Production-sharing contract (PSC) An agreement between a government and a contractor (generally an oil and gas company) whereby production is shared between the parties in a prearranged manner. The contractor typically incurs all exploration, development and production costs, which are subsequently recoverable out of an agreed-upon share of any future PSC production, referred to as cost recovery oil and/or gas. Any remaining production, referred to as profit oil and/or gas, is shared between the parties on an agreed-upon basis as stipulated in the PSC. The government also may retain a share of PSC production as a royalty payment, and the contractor typically owes income tax on its portion of the profit oil and/or gas. The contractor's share of PSC oil and/or gas production and reserves varies over time as it is dependent on prices, costs and specific PSC terms.

Renewables Energy resources that are not depleted when consumed or converted into other forms of energy (e.g., solar, geothermal, ocean and tide, wind, hydroelectric power, biofuels and hydrogen).

Reserves Crude oil and natural gas contained in underground rock formations called reservoirs and saleable hydrocarbons extracted from oil sands, shale, coalbeds and other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas. *Net proved reserves* are the estimated quantities that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in the future from known reservoirs under existing economic conditions, operating methods and government regulations, and exclude royalties and interests owned by others. Estimates change as additional information becomes available. *Oil-equivalent reserves* are the sum of the liquids reserves and the oil-equivalent gas reserves. See *barrels of oil-equivalent* and *oil-equivalent gas*. The company discloses only net proved reserves in its filings with the U.S. Securities and Exchange Commission. Investors should refer to proved reserves disclosures in Chevron's Annual Report on Form 10-K for the year ended December 31, 2014.

Resources Estimated quantities of oil and gas resources are recorded under Chevron's 6P system, which is modeled after the Society of Petroleum Engineers' Petroleum Resource Management System, and include quantities classified as proved, probable

and possible reserves, plus those that remain contingent on commerciality. *Unrisked resources*, *unrisked resource base* and similar terms represent the arithmetic sum of the amounts recorded under each of these classifications. *Recoverable resources*, *potentially recoverable volumes* and other similar terms represent estimated remaining quantities that are expected to be ultimately recoverable and produced in the future, adjusted to reflect the relative uncertainty represented by the various classifications. These estimates may change significantly as development work provides additional information. At times, *original oil in place* and similar terms are used to describe total hydrocarbons contained in a reservoir without regard to the likelihood of their being produced. All of these measures are considered by management in making capital investment and operating decisions and may provide some indication to stockholders of the resource potential of oil and gas properties in which the company has an interest.

Shale gas Natural gas produced from shale rock formations where the gas was sourced from within the shale itself. Shale is very fine-grained rock, characterized by low porosity and extremely low permeability. Production of shale gas normally requires formation stimulation such as the use of hydraulic fracturing (pumping a fluid-sand mixture into the formation under high pressure) to help produce the gas.

Synthetic oil A marketable and transportable hydrocarbon liquid, resembling crude oil, that is produced by upgrading highly viscous or solid hydrocarbons, such as extra-heavy crude oil or *oil sands*.

Tight oil Liquid hydrocarbons produced from shale (also referred to as shale oil) and other rock formations with extremely low permeability. As with shale gas, production from tight oil reservoirs normally requires formation stimulation such as hydraulic fracturing.

Financial Terms

Cash flow from operating activities Cash generated from the company's businesses; an indicator of a company's ability to fund capital programs and stockholder distributions. Excludes cash flows related to the company's financing and investing activities.

Earnings Net income attributable to Chevron Corporation as presented on the Consolidated Statement of Income.

Margin The difference between the cost of purchasing, producing and/or marketing a product and its sales price.

Return on capital employed (ROCE) Ratio calculated by dividing *earnings* (adjusted for after-tax interest expense and noncontrolling interests) by the average of total debt, noncontrolling interests and Chevron Corporation stockholders' equity for the year.

Return on stockholders' equity Ratio calculated by dividing *earnings* by average Chevron Corporation stockholders' equity. Average Chevron Corporation stockholders' equity is computed by averaging the sum of the beginning-of-year and end-of-year balances.

Total stockholder return (TSR) The return to stockholders as measured by stock price appreciation and reinvested dividends for a period of time.

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CAUTIONARY STATEMENT RELEVANT TO FORWARD-LOOKING INFORMATION FOR THE PURPOSE OF "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This *Annual Report* of Chevron Corporation contains forward-looking statements relating to Chevron's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as "anticipates," "expects," "intends," "plans," "targets," "forecasts," "projects," "believes," "seeks," "schedules," "estimates," "may," "could," "budgets," "outlook" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, many of which are beyond the company's control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude oil and natural gas prices; changing refining, marketing and chemicals margins; actions of competitors or regulators; timing of exploration expenses; timing of crude oil liftings; the competitiveness of alternate-energy sources or product substitutes; technological developments; the results of operations and financial condition of equity affiliates; the inability or failure of the company's joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company's production or manufacturing facilities or delivery/transportation networks due to war, accidents, political events, civil unrest, severe weather, other natural or human factors, or crude oil production quotas that might be imposed by the Organization of Petroleum Exporting Countries; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant investment or product changes required by existing or future environmental statutes, regulations and litigation; the potential liability resulting from other pending or future litigation; the company's future acquisition or disposition of assets and gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; and the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies. In addition, such results could be affected by general domestic and international economic and political conditions. Other unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Key Financial Results

<i>Millions of dollars, except per-share amounts</i>	2014	2013	2012
Net Income Attributable to Chevron Corporation	\$ 19,241	\$ 21,423	\$ 26,179
Per Share Amounts:			
Net Income Attributable to Chevron Corporation			
– Basic	\$ 10.21	\$ 11.18	\$ 13.42
– Diluted	\$ 10.14	\$ 11.09	\$ 13.32
Dividends	\$ 4.21	\$ 3.90	\$ 3.51
Sales and Other Operating Revenues	\$ 200,494	\$ 220,156	\$ 230,590
Return on:			
Capital Employed	10.9%	13.5%	18.7%
Stockholders' Equity	12.7%	15.0%	20.3%

Earnings by Major Operating Area

<i>Millions of dollars</i>	2014	2013	2012
Upstream			
United States	\$ 3,327	\$ 4,044	\$ 5,332
International	13,566	16,765	18,456
Total Upstream	16,893	20,809	23,788
Downstream			
United States	2,637	787	2,048
International	1,699	1,450	2,251
Total Downstream	4,336	2,237	4,299
All Other	(1,988)	(1,623)	(1,908)
Net Income Attributable to Chevron Corporation^{1,2}	\$ 19,241	\$ 21,423	\$ 26,179
¹ Includes foreign currency effects:	\$ 487	\$ 474	\$ (454)

² Income net of tax, also referred to as “earnings” in the discussions that follow.

Refer to the “Results of Operations” section beginning on page 15 for a discussion of financial results by major operating area for the three years ended December 31, 2014.

Business Environment and Outlook

Chevron is a global energy company with substantial business activities in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Canada, China, Colombia, Democratic Republic of the Congo, Denmark, Indonesia, Kazakhstan, Myanmar, Nigeria, the Partitioned Zone between Saudi Arabia and Kuwait, the Philippines, Republic of the Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, the United States, Venezuela, and Vietnam.

Earnings of the company depend mostly on the profitability of its upstream business segment. The biggest factor affecting the results of operations for the upstream segment is the price of crude oil. The price of crude oil has fallen significantly since mid-year 2014, reflecting robust non-OPEC supply growth led by expanding unconventional production in the United States, weakening growth in emerging markets, and the decision by OPEC in fourth quarter 2014 to maintain its current production ceiling. The downturn in the price of crude oil has impacted, and, depending upon its duration, will continue to significantly impact the company's results of operations, cash flows, capital and exploratory investment program and production outlook. If lower prices persist for an extended period of time, the company's response could include further reductions in operating expenses and capital and exploratory expenditures and additional asset sales. The company anticipates that crude oil prices will increase in the future, as continued growth in demand and a slowing in supply growth should bring global markets into balance; however, the timing of any such increases is unknown. In the company's downstream business, crude oil is the largest cost component of refined products.

Refer to the “Cautionary Statement Relevant to Forward-Looking Information” on page 9 and to “Risk Factors” in Part I, Item 1A, on pages 22 through 24 on the company's Annual Report on Form 10-K for a discussion of some of the inherent risks that could materially impact the company's results of operations or financial condition.

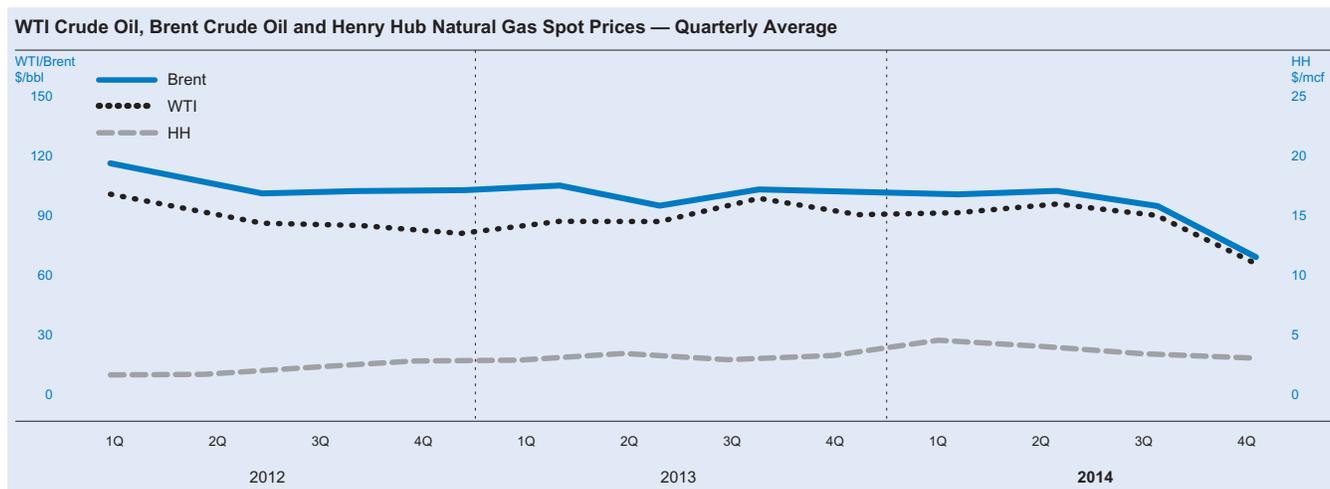
The company continually evaluates opportunities to dispose of assets that are not expected to provide sufficient long-term value or to acquire assets or operations complementary to its asset base to help augment the company's financial performance and growth. Refer to the “Results of Operations” section beginning on page 15 for discussions of net gains on asset sales during 2014. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

The company closely monitors developments in the financial and credit markets, the level of worldwide economic activity, and the implications for the company of changes in prices for crude oil and natural gas. Management takes these developments into account in the conduct of ongoing operations and for business planning.

Comments related to earnings trends for the company's major business areas are as follows:

Upstream Earnings for the upstream segment are closely aligned with industry prices for crude oil and natural gas. Crude oil and natural gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry inventory levels, production quotas or other actions imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damage and disruptions, competing fuel prices, and regional supply interruptions or fears thereof that may be caused by military conflicts, civil unrest or political uncertainty. Any of these factors could also inhibit the company's production capacity in an affected region. The company closely monitors developments in the countries in which it operates and holds investments, and seeks to manage risks in operating its facilities and businesses. The longer-term trend in earnings for the upstream segment is also a function of other factors, including the company's ability to find or acquire and efficiently produce crude oil and natural gas, changes in fiscal terms of contracts, and changes in tax laws and regulations.

The company continues to actively manage its schedule of work, contracting, procurement and supply-chain activities to effectively manage costs. However, price levels for capital and exploratory costs and operating expenses associated with the production of crude oil and natural gas can be subject to external factors beyond the company's control including, among other things, the general level of inflation, commodity prices and prices charged by the industry's material and service providers, which can be affected by the volatility of the industry's own supply-and-demand conditions for such materials and services. In recent years, Chevron and the oil and gas industry generally experienced an increase in certain costs that exceeded the general trend of inflation in many areas of the world. As a result of the decline in prices of crude oil and other commodities in 2014, these cost pressures are beginning to soften. Capital and exploratory expenditures and operating expenses can also be affected by damage to production facilities caused by severe weather or civil unrest.



The chart above shows the trend in benchmark prices for Brent crude oil, West Texas Intermediate (WTI) crude oil and U.S. Henry Hub natural gas. The Brent price averaged \$99 per barrel for the full-year 2014, compared to \$109 in 2013. As of mid-February 2015, the Brent price was \$60 per barrel. The majority of the company's equity crude production is priced based on the Brent benchmark. While geopolitical tensions and supply disruptions supported crude prices through mid-year, crude prices have since been in decline, as signs of crude oil over-supply emerged during the second half of the year due to continued robust non-OPEC supply growth, concern over softness in the global economic recovery, and material easing of geopolitical tensions and supply disruptions. Downward pressure on crude pricing has been further magnified by OPEC's decision in November 2014 to maintain the current production ceiling of 30 million barrels per day despite evidence of market surplus.

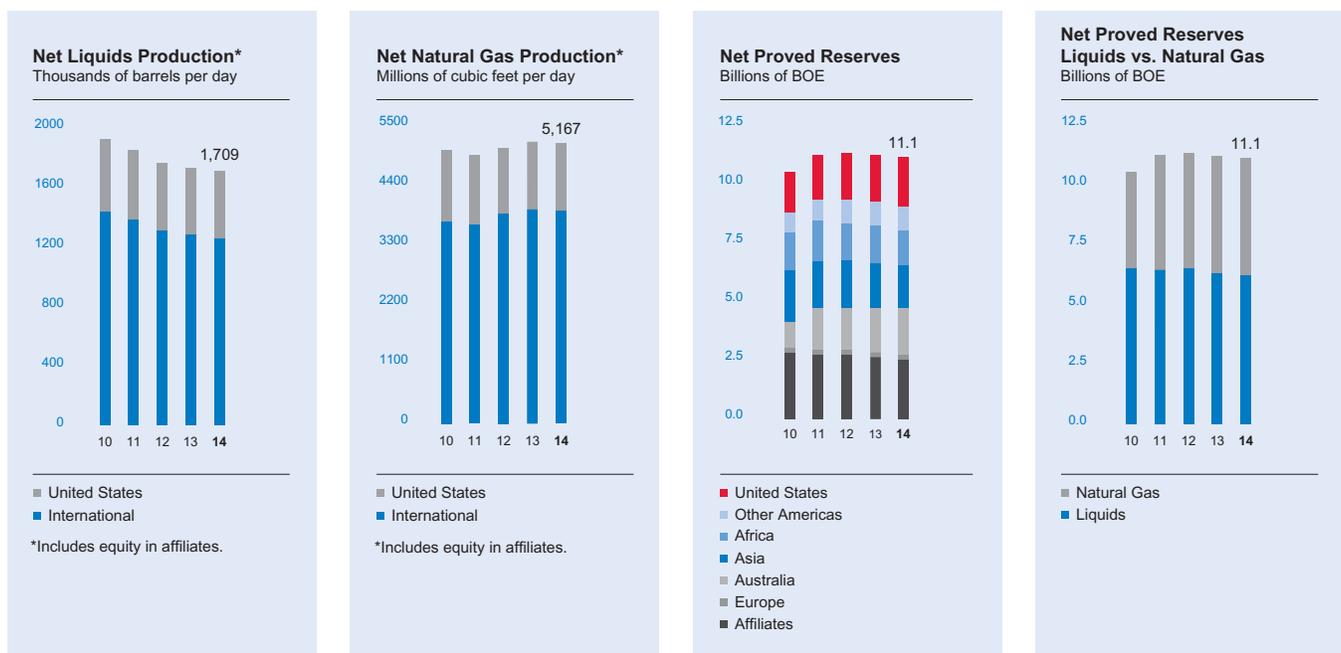
The WTI price averaged \$93 per barrel for the full-year 2014, compared to \$98 in 2013. As of mid-February 2015, the WTI price was \$53 per barrel. WTI traded at a discount to Brent throughout 2014 due to high inventories and excess crude supply in the U.S. market.

A differential in crude oil prices exists between high-quality (high-gravity, low-sulfur) crudes and those of lower quality (low-gravity, high-sulfur). The amount of the differential in any period is associated with the supply of heavy crude versus the demand, which is a function of the capacity of refineries that are able to process this lower quality feedstock into light products (motor gasoline, jet fuel, aviation gasoline and diesel fuel). After peaking early in second quarter 2014, the differential has eased in North America as refinery crude runs remained at or above record levels. Outside of North America, easing of geopolitical tensions and continued expansion of supply of light sweet crudes has pressured light sweet crude prices relative to those for heavier, more sour crudes.

Chevron produces or shares in the production of heavy crude oil in California, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom sector of the North Sea. (See page 19 for the company's average U.S. and international crude oil realizations.)

In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply-and-demand conditions in those markets. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced and stored in North America. In the United States, prices at Henry Hub averaged \$4.28 per thousand cubic feet (MCF) during 2014, compared with \$3.70 during 2013. As of mid-February 2015, the Henry Hub spot price was \$2.73 per MCF.

Outside the United States, price changes for natural gas depend on a wide range of supply, demand, regulatory and commercial factors. In some locations, Chevron is investing in long-term projects to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets. The company's contract prices for liquefied natural gas (LNG) are typically linked to crude oil prices. Chevron's international natural gas realizations averaged \$5.78 per MCF during 2014, compared with \$5.91 per MCF during 2013. (See page 19 for the company's average natural gas realizations for the U.S. and international regions.)



The company's worldwide net oil-equivalent production in 2014 averaged 2.571 million million barrels per day. About one-fifth of the company's net oil-equivalent production in 2014 occurred in the OPEC-member countries of Angola, Nigeria, Venezuela and the Partitioned Zone between Saudi Arabia and Kuwait. OPEC quotas had no effect on the company's net crude oil production in 2014 or 2013. At their November 2014 meeting, members of OPEC supported maintaining the current production quota of 30 million barrels per day, which has been in effect since December 2008.

The company estimates that oil-equivalent production in 2015 will be flat to 3 percent growth compared to 2014. This estimate is subject to many factors and uncertainties, including the duration of the low price environment that began in second-half 2014; quotas that may be imposed by OPEC; price effects on entitlement volumes; changes in fiscal terms or restrictions on the scope of company operations; delays in construction, start-up or ramp-up of projects; fluctuations in demand for natural gas in various markets; weather conditions that may shut in production; civil unrest; changing geopolitics; delays in completion of maintenance turnarounds; greater-than-expected declines in production from mature

fields; or other disruptions to operations. The outlook for future production levels is also affected by the size and number of economic investment opportunities and, for new, large-scale projects, the time lag between initial exploration and the beginning of production. Investments in upstream projects generally begin well in advance of the start of the associated crude oil and natural gas production. A significant majority of Chevron's upstream investment is made outside the United States.

Net proved reserves for consolidated companies and affiliated companies totaled 11.1 billion barrels of oil equivalent at year-end 2014, a decrease of 1 percent from year-end 2013. The reserve replacement ratio in 2014 was 89 percent. Refer to Table V beginning on page 74 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2012 and each year-end from 2012 through 2014, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2014.

On November 7, 2011, while drilling a development well in the deepwater Frade Field about 75 miles offshore Brazil, an unanticipated pressure spike caused oil to migrate from the well bore through a series of fissures to the sea floor, emitting approximately 2,400 barrels of oil. The source of the seep was substantially contained within four days and the well was plugged and abandoned. On March 14, 2012, the company identified a small, second seep in a different part of the field. No evidence of any coastal or wildlife impacts related to either of these seeps have emerged. As reported in the company's previously filed periodic reports, it has resolved civil claims relating to these incidents brought by a Brazilian federal district prosecutor. As also reported previously, the federal district prosecutor also filed criminal charges against Chevron and eleven Chevron employees. On February 19, 2013, the trial court dismissed the criminal matter, and on appeal, on October 9, 2013, the appellate court reinstated two of the ten allegations, specifically those charges alleging environmental damage and failure to provide timely notification to authorities. On February 27, 2014, Chevron filed a motion for reconsideration. While reconsideration of the motion to dismiss is pending, there will be further proceedings on the reinstated allegations. The company's ultimate exposure related to the incident is not currently determinable.

Refer to the "Results of Operations" section on pages 15 through 17 for additional discussion of the company's upstream business.

Downstream Earnings for the downstream segment are closely tied to margins on the refining, manufacturing and marketing of products that include gasoline, diesel, jet fuel, lubricants, fuel oil, fuel and lubricant additives, and petrochemicals. Industry margins are sometimes volatile and can be affected by the global and regional supply-and-demand balance for refined products and petrochemicals and by changes in the price of crude oil, other refinery and petrochemical feedstocks, and natural gas. Industry margins can also be influenced by inventory levels, geopolitical events, costs of materials and services, refinery or chemical plant capacity utilization, maintenance programs, and disruptions at refineries or chemical plants resulting from unplanned outages due to severe weather, fires or other operational events.

Other factors affecting profitability for downstream operations include the reliability and efficiency of the company's refining, marketing and petrochemical assets, the effectiveness of its crude oil and product supply functions, and the volatility of tanker-charter rates for the company's shipping operations, which are driven by the industry's demand for crude oil and product tankers. Other factors beyond the company's control include the general level of inflation and energy costs to operate the company's refining, marketing and petrochemical assets.

The company's most significant marketing areas are the West Coast of North America, the U.S. Gulf Coast, Asia and southern Africa. Chevron operates or has significant ownership interests in refineries in each of these areas.

Refer to the "Results of Operations" section on pages 15 through 17 for additional discussion of the company's downstream operations.

All Other consists of mining activities, power and energy services, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, and technology companies.

Operating Developments

Key operating developments and other events during 2014 and early 2015 included the following:

Upstream

Argentina Signed additional agreements to continue the development of the Loma Campana Project in the Vaca Muerta Shale, and to begin exploration in the Narambuena area of the Neuquén Basin.

Australia Announced in January 2015 an additional binding sales agreement for delivery of LNG from the Gorgon Project for a five-year period starting in 2017. During the time of this agreement, more than 75 percent of Chevron's equity LNG offtake from the project is committed under binding sales agreements to customers in Asia.

Azerbaijan Achieved first production from the Chirag Oil Project in the Caspian Sea.

Bangladesh Announced first gas from the Bibiyana Expansion Project.

Canada Completed the sale of a 30 percent interest in the Duvernay shale play for \$1.5 billion.

Chad/Cameroon Completed the sale of the company's nonoperated interest in a producing concession in Chad and the related export pipeline interests in Chad and Cameroon for approximately \$1.3 billion.

Kazakhstan/Russia Achieved a 230,000-barrel-per-day increase in capacity of the Caspian Pipeline Consortium pipeline.

Mauritania In early 2015, the company reached agreement to acquire a 30 percent nonoperated working interest in three contract areas offshore Mauritania, pending government approval.

Myanmar Announced the acquisition of offshore acreage.

New Zealand Announced the acquisition of three offshore blocks.

Nigeria Achieved initial production of product at the Escravos Gas-to-Liquids facility.

United States Announced initial crude oil and natural gas production from the Jack/St. Malo and Tubular Bells projects in the deepwater Gulf of Mexico.

Made significant crude oil discoveries at the Guadalupe and Anchor prospects in the deepwater Gulf of Mexico.

In early 2015, announced a joint venture to explore and appraise 24 jointly-held offshore leases in the northwest portion of Keathley Canyon in the deepwater Gulf of Mexico. The joint venture includes the Tiber and Gila discoveries and the Gibson prospect. The company acquired a 36 percent working interest in the Gila leases and 31 percent working interest in the Tiber leases and previously held a working interest in Gibson.

Reached a final investment decision for the Stampede Project in the deepwater Gulf of Mexico.

Completed the sale of natural gas liquids pipeline assets in Texas and southeastern New Mexico for \$800 million.

Drilled 550 wells during 2014 in the Midland and Delaware basins in West Texas and southeast New Mexico.

Downstream

France Completed expansion project at the additives plant in Gonfreville, France.

Singapore Completed expansion project at the additives plant in Singapore.

United States Commenced commercial production at the new premium lubricants base oil facility in Pascagoula, Mississippi.

The company's 50 percent-owned Chevron Phillips Chemical Company, LLC (CPChem) achieved start-up of the world's largest on-purpose 1-hexene plant, with a capacity of 250,000 metric tons per year, at its Cedar Bayou complex in Baytown, Texas.

Progressed construction of CPChem's U.S. Gulf Coast Petrochemicals Project.

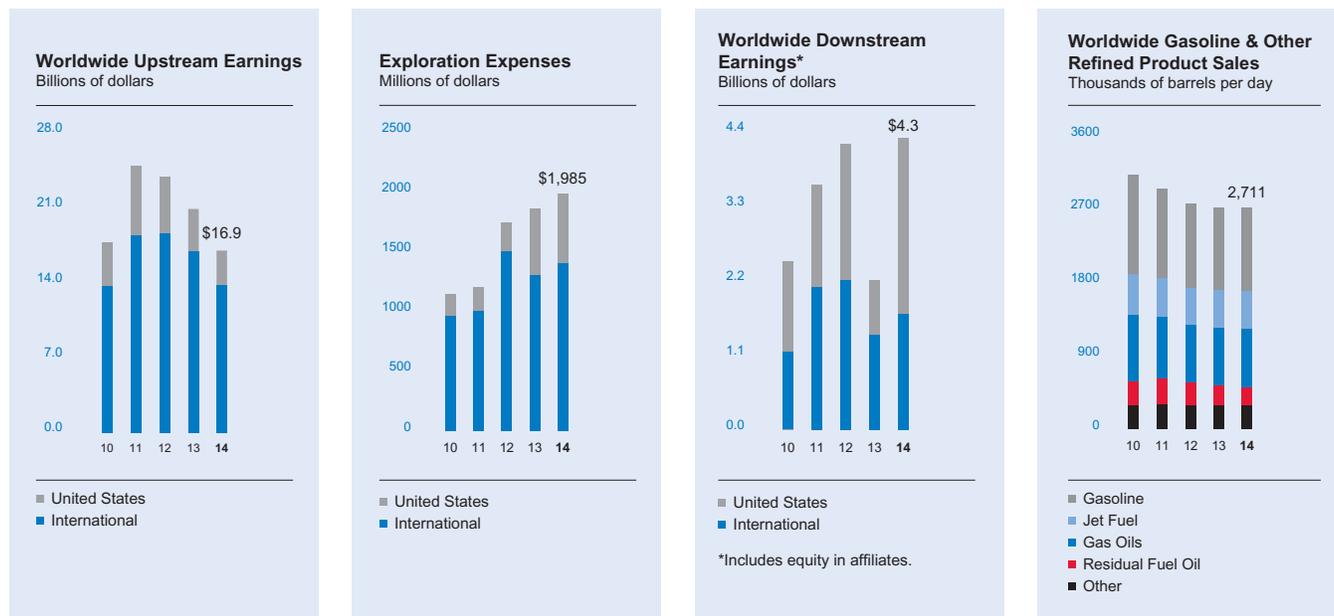
Other

Common Stock Dividends The quarterly common stock dividend was increased by 7.0 percent in April 2014 to \$1.07 per common share, making 2014 the 27th consecutive year that the company increased its annual dividend payout.

Common Stock Repurchase Program The company purchased \$5.0 billion of its common stock in 2014 under its share repurchase program. Given the change in market conditions, the company is suspending the share repurchase program for 2015.

Results of Operations

The following section presents the results of operations and variances on an after-tax basis for the company's business segments – Upstream and Downstream – as well as for “All Other.” Earnings are also presented for the U.S. and international geographic areas of the Upstream and Downstream business segments. Refer to Note 12, beginning on page 45, for a discussion of the company's “reportable segments.” This section should also be read in conjunction with the discussion in “Business Environment and Outlook” on pages 10 through 13.



U.S. Upstream

Millions of dollars	2014	2013	2012
Earnings	\$ 3,327	\$ 4,044	\$ 5,332

U.S. upstream earnings of \$3.3 billion in 2014 decreased \$717 million from 2013, primarily due to lower crude oil prices of \$950 million. Higher depreciation expenses of \$440 million and higher operating expenses of \$210 million also contributed to the decline. Partially offsetting the decrease were higher gains on asset sales of \$700 million in the current period compared with \$60 million in 2013, higher natural gas realizations of \$150 million and higher crude oil production of \$100 million.

U.S. upstream earnings of \$4.0 billion in 2013 decreased \$1.3 billion from 2012, primarily due to higher operating, depreciation and exploration expenses of \$420 million, \$350 million, and \$190 million, respectively, and lower crude oil production of \$170 million. Higher natural gas realizations of approximately \$200 million were mostly offset by lower crude oil realizations of \$170 million.

The company's average realization for U.S. crude oil and natural gas liquids in 2014 was \$84.13 per barrel, compared with \$93.46 in 2013 and \$95.21 in 2012. The average natural gas realization was \$3.90 per thousand cubic feet in 2014, compared with \$3.37 and \$2.64 in 2013 and 2012, respectively.

Net oil-equivalent production in 2014 averaged 664,000 barrels per day, up 1 percent from both 2013 and 2012. Between 2014 and 2013, production increases in the Permian Basin in Texas and New Mexico and the Marcellus Shale in western Pennsylvania were partially offset by normal field declines. Between 2013 and 2012, new production in the Marcellus Shale in western Pennsylvania and the Delaware Basin in New Mexico, along with the absence of weather-related downtime in the Gulf of Mexico, was largely offset by normal field declines.

The net liquids component of oil-equivalent production for 2014 averaged 456,000 barrels per day, up 2 percent from 2013 and largely unchanged from 2012. Net natural gas production averaged about 1.3 billion cubic feet per day in 2014, largely unchanged from 2013 and up 4 percent from 2012. Refer to the “Selected Operating Data” table on page 19 for a three-year comparative of production volumes in the United States.

International Upstream

<i>Millions of dollars</i>	2014	2013	2012
Earnings*	\$ 13,566	\$ 16,765	\$ 18,456
*Includes foreign currency effects:	\$ 597	\$ 559	\$ (275)

International upstream earnings were \$13.6 billion in 2014 compared with \$16.8 billion in 2013. The decrease between periods was primarily due to lower crude oil prices and sales volumes of \$2.0 billion and \$400 million, respectively. Also contributing to the decrease were higher depreciation expenses of \$1.0 billion, mainly related to impairments and other asset writeoffs, and higher operating and tax expenses of \$340 million and \$310 million, respectively. Partially offsetting these items were gains on asset sales of \$1.1 billion in 2014, compared with \$140 million in 2013. Foreign currency effects increased earnings by \$597 million in 2014, compared with an increase of \$559 million a year earlier.

International upstream earnings were \$16.8 billion in 2013 compared with \$18.5 billion in 2012. The decrease was mainly due to the absence of 2012 gains of approximately \$1.4 billion on an asset exchange in Australia and \$600 million on the sale of an equity interest in the Wheatstone Project, lower crude oil prices of \$500 million, and higher operating expense of \$400 million. Partially offsetting these effects were lower income tax expenses of \$430 million. Foreign currency effects increased earnings by \$559 million in 2013, compared with a decrease of \$275 million a year earlier.

The company's average realization for international crude oil and natural gas liquids in 2014 was \$90.42 per barrel, compared with \$100.26 in 2013 and \$101.88 in 2012. The average natural gas realization was \$5.78 per thousand cubic feet in 2014, compared with \$5.91 and \$5.99 in 2013 and 2012, respectively.

International net oil-equivalent production was 1.91 million barrels per day in 2014, a decrease of 2 percent from 2013 and 2012. Production increases due to project ramp-ups in Nigeria, Argentina and Brazil in 2014 were more than offset by normal field declines, production entitlement effects in several locations and the effect of asset sales. The decline between 2013 and 2012 was a result of project ramp-ups in Nigeria and Angola in 2013 being more than offset by normal field declines.

The net liquids component of international oil-equivalent production was 1.25 million barrels per day in 2014, a decrease of approximately 2 percent from 2013 and a decrease of approximately 4 percent from 2012. International net natural gas production of 3.9 billion cubic feet per day in 2014 was down 1 percent from 2013 and up 1 percent from 2012.

Refer to the "Selected Operating Data" table, on page 19, for a three-year comparative of international production volumes.

U.S. Downstream

<i>Millions of dollars</i>	2014	2013	2012
Earnings	\$ 2,637	\$ 787	\$ 2,048

U.S. downstream operations earned \$2.6 billion in 2014, compared with \$787 million in 2013. Higher margins on refined product sales increased earnings \$830 million. Gains from asset sales were \$960 million in 2014, compared with \$250 million a year earlier. Higher earnings from 50 percent-owned CPChem of \$160 million and lower operating expenses of \$80 million also contributed to the earnings increase.

U.S. downstream operations earned \$787 million in 2013, compared with \$2.0 billion in 2012. The decrease was mainly due to lower margins on refined product sales of \$860 million and higher operating expenses of \$600 million, reflecting repair and maintenance activities at the company's refineries. The decrease was partially offset by higher earnings of \$150 million from 50 percent-owned CPChem.

Refined product sales of 1.21 million barrels per day in 2014 increased 2 percent, mainly reflecting higher gas oil sales. Sales volumes of refined products were 1.18 million barrels per day in 2013, a decrease of 2 percent from 2012, mainly reflecting lower gas oil and gasoline sales. U.S. branded gasoline sales of 516,000 barrels per day in 2014 were essentially unchanged from 2013 and 2012.

Refer to the "Selected Operating Data" table on page 19 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

<i>Millions of dollars</i>	2014	2013	2012
Earnings*	\$ 1,699	\$ 1,450	\$ 2,251
*Includes foreign currency effects:	\$ (112)	\$ (76)	\$ (173)

International downstream earned \$1.7 billion in 2014, compared with \$1.5 billion in 2013. The increase was mainly due to a favorable change in the effects on derivative instruments of \$640 million. The increase was partially offset by the economic buyout of a legacy pension obligation of \$160 million in the current period, lower margins on refined product sales of \$130 million and higher tax expenses of \$110 million. Foreign currency effects decreased earnings by \$112 million in 2014, compared to a decrease of \$76 million a year earlier.

International downstream earned \$1.5 billion in 2013, compared with \$2.3 billion in 2012. Earnings decreased due to lower gains on asset sales of \$540 million and higher income tax expenses of \$110 million. Foreign currency effects decreased earnings by \$76 million in 2013, compared with a decrease of \$173 million a year earlier.

Total refined product sales of 1.50 million barrels per day in 2014 declined 2 percent from 2013, mainly reflecting lower gas oil sales. Sales of 1.53 million barrels per day in 2013 declined 2 percent from 2012, mainly reflecting lower fuel oil and gasoline sales.

Refer to the "Selected Operating Data" table, on page 19, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

<i>Millions of dollars</i>	2014	2013	2012
Net charges*	\$ (1,988)	\$ (1,623)	\$ (1,908)
*Includes foreign currency effects:	\$ 2	\$ (9)	\$ (6)

All Other consists of mining activities, power and energy services, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, and technology companies.

Net charges in 2014 increased \$365 million from 2013, mainly due to environmental reserves additions, asset impairments and additional asset retirement obligations for mining assets, as well as higher corporate tax items. These increases were partially offset by the absence of 2013 impairments of power-related affiliates and lower other corporate charges. Net charges in 2013 decreased \$285 million from 2012, mainly due to lower corporate tax items and other corporate charges.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

<i>Millions of dollars</i>	2014	2013	2012
Sales and other operating revenues	\$ 200,494	\$ 220,156	\$ 230,590

Sales and other operating revenues decreased in 2014 primarily due to lower crude oil volumes, and lower refined product and crude oil prices. The decrease between 2013 and 2012 was mainly due to lower refined product prices and lower crude oil volumes and prices.

<i>Millions of dollars</i>	2014	2013	2012
Income from equity affiliates	\$ 7,098	\$ 7,527	\$ 6,889

Income from equity affiliates decreased in 2014 from 2013 mainly due to lower upstream-related earnings from Tengizchevroil in Kazakhstan, Petropiar and Petroboscan in Venezuela, and Angola LNG. Partially offsetting these effects were higher downstream-related earnings from GS Caltex in South Korea, higher earnings from CPChem and the absence of 2013 impairments of power-related affiliates.

Income from equity affiliates increased in 2013 from 2012 mainly due to higher upstream-related earnings from Tengizchevroil in Kazakhstan and Petropiar in Venezuela, and higher earnings from CPChem, partially offset by 2013 impairments of power-related affiliates.

Refer to Note 13, beginning on page 48, for a discussion of Chevron's investments in affiliated companies.

<i>Millions of dollars</i>	2014	2013	2012
Other income	\$ 4,378	\$ 1,165	\$ 4,430

Other income of \$4.4 billion in 2014 included net gains from asset sales of \$3.6 billion before-tax. Other income in 2013 and 2012 included net gains from asset sales of \$710 million and \$4.2 billion before-tax, respectively. Interest income was approximately \$145 million in 2014, \$136 million in 2013 and \$166 million in 2012. Foreign currency effects increased other income by \$277 million in 2014, while increasing other income by \$103 million in 2013 and decreasing other income by \$207 million in 2012.

<i>Millions of dollars</i>	2014	2013	2012
Purchased crude oil and products	\$ 119,671	\$ 134,696	\$ 140,766

Crude oil and product purchases of \$119.7 billion were down in 2014 mainly due to lower crude oil and refined products prices, along with lower crude oil volumes. Crude oil and product purchases in 2013 decreased by \$6.1 billion from the prior year, mainly due to lower prices for refined products and lower volumes for crude oil, partially offset by higher refined product volumes.

<i>Millions of dollars</i>	2014	2013	2012
Operating, selling, general and administrative expenses	\$ 29,779	\$ 29,137	\$ 27,294

Operating, selling, general and administrative expenses increased \$642 million between 2014 and 2013. The increase included higher employee compensation and benefit costs of \$360 million, primarily related to a buyout of a legacy pension obligation. Also contributing to the increase was higher transportation costs of \$350 million, primarily reflecting the economic buyout of a long-term contractual obligation, and higher environmental expenses related to a mining asset of \$300 million. Partially offsetting the increase were lower fuel expenses of \$360 million.

Operating, selling, general and administrative expenses increased \$1.8 billion between 2013 and 2012 mainly due to higher employee compensation and benefits costs of \$720 million, construction and maintenance expenses of \$590 million, and professional services costs of \$500 million.

<i>Millions of dollars</i>	2014	2013	2012
Exploration expense	\$ 1,985	\$ 1,861	\$ 1,728

Exploration expenses in 2014 increased from 2013 mainly due to higher charges for well write-offs, partially offset by lower geological and geophysical expenses. Exploration expenses in 2013 increased from 2012 mainly due to higher charges for well write-offs.

<i>Millions of dollars</i>	2014	2013	2012
Depreciation, depletion and amortization	\$ 16,793	\$ 14,186	\$ 13,413

Depreciation, depletion and amortization expenses increased in 2014 from 2013 mainly due to higher depreciation rates and impairments for certain oil and gas producing fields, and the impairment of a mining asset. The increase in 2013 from 2012 was mainly due to higher depreciation rates for certain oil and gas producing fields, higher upstream impairments and higher accretion expense, partially offset by lower production levels.

<i>Millions of dollars</i>	2014	2013	2012
Taxes other than on income	\$ 12,540	\$ 13,063	\$ 12,376

Taxes other than on income decreased in 2014 from 2013 mainly due to a decrease in duty expense in South Africa along with lower consumer excise taxes in Thailand, reflecting lower sales volumes at both locations. Taxes other than on income increased in 2013 from 2012 primarily due to the consolidation of the 64 percent-owned Star Petroleum Refining Company, beginning June 2012, and higher consumer excise taxes in the United States.

<i>Millions of dollars</i>	2014	2013	2012
Income tax expense	\$ 11,892	\$ 14,308	\$ 19,996

Effective income tax rates were 38 percent in 2014, 40 percent in 2013 and 43 percent in 2012. The decrease in the effective tax rate between 2014 and 2013 primarily resulted from the impact of changes in jurisdictional mix and equity earnings, and

the tax effects related to the 2014 sale of interests in Chad and Cameroon, partially offset by other one-time and ongoing tax charges.

The rate decreased between 2013 and 2012 primarily due to a lower effective tax rate in international upstream operations. The lower international upstream effective tax rate was driven by a greater portion of equity income in 2013 than in 2012 (equity income is included as part of before-tax income and is generally recorded net of income taxes) and foreign currency remeasurement impacts.

Selected Operating Data^{1,2}

	2014	2013	2012
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	456	449	455
Net Natural Gas Production (MMCFPD) ³	1,250	1,246	1,203
Net Oil-Equivalent Production (MBOEPD)	664	657	655
Sales of Natural Gas (MMCFPD)	3,995	5,483	5,470
Sales of Natural Gas Liquids (MBPD)	20	17	16
Revenues From Net Production			
Liquids (\$/Bbl)	\$ 84.13	\$ 93.46	\$ 95.21
Natural Gas (\$/MCF)	\$ 3.90	\$ 3.37	\$ 2.64
International Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD) ⁴	1,253	1,282	1,309
Net Natural Gas Production (MMCFPD) ³	3,917	3,946	3,871
Net Oil-Equivalent Production (MBOEPD) ⁴	1,907	1,940	1,955
Sales of Natural Gas (MMCFPD)	4,304	4,251	4,315
Sales of Natural Gas Liquids (MBPD)	28	26	24
Revenues From Liftings			
Liquids (\$/Bbl)	\$ 90.42	\$ 100.26	\$ 101.88
Natural Gas (\$/MCF)	\$ 5.78	\$ 5.91	\$ 5.99
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD) ⁴			
United States	664	657	655
International	1,907	1,940	1,955
Total	2,571	2,597	2,610
U.S. Downstream			
Gasoline Sales (MBPD) ⁵	615	613	624
Other Refined Product Sales (MBPD)	595	569	587
Total Refined Product Sales (MBPD)	1,210	1,182	1,211
Sales of Natural Gas Liquids (MBPD)	121	125	141
Refinery Input (MBPD)	871	774	833
International Downstream			
Gasoline Sales (MBPD) ⁵	403	398	412
Other Refined Product Sales (MBPD)	1,098	1,131	1,142
Total Refined Product Sales (MBPD) ⁶	1,501	1,529	1,554
Sales of Natural Gas Liquids (MBPD)	58	62	64
Refinery Input (MBPD) ⁷	819	864	869

¹ Includes company share of equity affiliates.

² MBPD – thousands of barrels per day; MMCFPD – millions of cubic feet per day; MBOEPD – thousands of barrels of oil-equivalents per day; Bbl – Barrel; MCF – Thousands of cubic feet. Oil-equivalent gas (OEG) conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of oil.

³ Includes natural gas consumed in operations (MMCFPD):

United States	71	72	65
International ⁸	452	458	457

⁴ Includes net production of synthetic oil:

Canada	43	43	43
Venezuela affiliate	31	25	17

⁵ Includes branded and unbranded gasoline.

⁶ Includes sales of affiliates (MBPD):

	475	471	522
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⁷ As of June 2012, Star Petroleum Refining Company crude-input volumes are reported on a 100 percent consolidated basis. Prior to June 2012, crude-input volumes reflect a 64 percent equity interest. In fourth quarter 2014, Caltex Australia Ltd. completed the conversion of the 68,000-barrel-per-day Kurnell refinery into an import terminal.

⁸ 2013 conforms to 2014 presentation.

Liquidity and Capital Resources

Cash, Cash Equivalents, Time Deposits and Marketable Securities Total balances were \$13.2 billion and \$16.5 billion at December 31, 2014 and 2013, respectively. Cash provided by operating activities in 2014 was \$31.5 billion, compared with \$35.0 billion in 2013 and \$38.8 billion in 2012. Cash provided by operating activities was net of contributions to employee pension plans of approximately \$0.4 billion, \$1.2 billion and \$1.2 billion in 2014, 2013 and 2012, respectively. Cash provided by investing activities included proceeds and deposits related to asset sales of \$5.7 billion in 2014, \$1.1 billion in 2013, and \$2.8 billion in 2012.

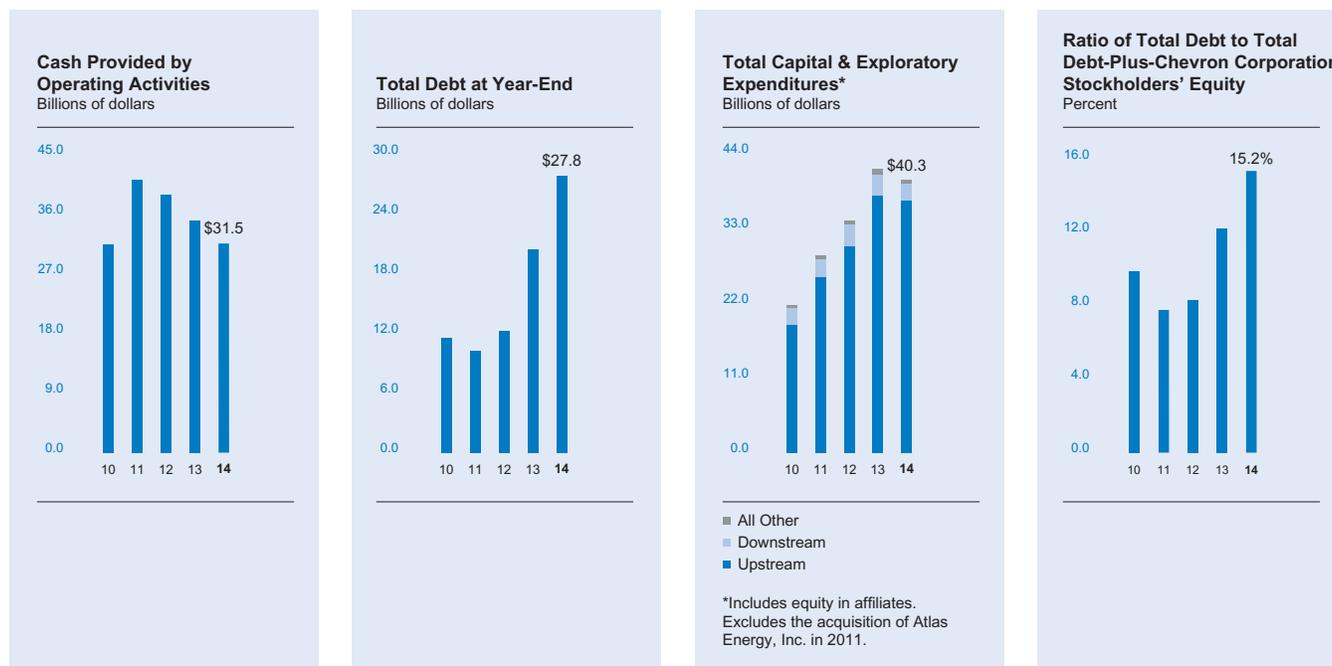
Restricted cash of \$1.5 billion and \$1.2 billion at December 31, 2014 and 2013, respectively, was held in cash and short-term marketable securities and recorded as “Deferred charges and other assets” on the Consolidated Balance Sheet. These amounts are generally associated with tax payments, upstream abandonment activities, funds held in escrow for asset acquisitions and capital investment projects.

Dividends Dividends paid to common stockholders were \$7.9 billion in 2014, \$7.5 billion in 2013 and \$6.8 billion in 2012. In April 2014, the company increased its quarterly dividend by 7 percent to \$1.07 per common share.

Debt and Capital Lease Obligations Total debt and capital lease obligations were \$27.8 billion at December 31, 2014, up from \$20.4 billion at year-end 2013.

The \$7.4 billion increase in total debt and capital lease obligations during 2014 was primarily due to funding the company’s capital investment program, which included several large projects in the construction phase. The company completed a \$4 billion bond issuance in November 2014, timed in part to take advantage of historically low interest rates. The company’s debt and capital lease obligations due within one year, consisting primarily of commercial paper, redeemable long-term obligations and the current portion of long-term debt, totaled \$11.8 billion at December 31, 2014, compared with \$8.4 billion at year-end 2013. Of these amounts, \$8.0 billion was reclassified to long-term at the end of both periods. At year-end 2014, settlement of these obligations was not expected to require the use of working capital in 2015, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

Chevron has an automatic shelf registration statement that expires in November 2015 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.



The major debt rating agencies routinely evaluate the company’s debt, and the company’s cost of borrowing can increase or decrease depending on these debt ratings. The company has outstanding public bonds issued by Chevron Corporation and Texaco Capital Inc. All of these securities are the obligations of, or guaranteed by, Chevron Corporation and are rated AA by Standard & Poor’s Corporation and Aa1 by Moody’s Investors Service. The company’s U.S. commercial paper is rated A-1+ by Standard & Poor’s and P-1 by Moody’s. All of these ratings denote high-quality, investment-grade securities.

The company's future debt level is dependent primarily on results of operations, the capital program and cash that may be generated from asset dispositions. Based on its high-quality debt ratings, the company believes that it has substantial borrowing capacity to meet unanticipated cash requirements. During extended periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals, the company can also modify capital spending plans to provide flexibility to continue paying the common stock dividend and with the intent to maintain the company's high-quality debt ratings.

Committed Credit Facilities Information related to committed credit facilities is included in Note 18 to the Consolidated Financial Statements, Short-Term Debt, on page 57.

Common Stock Repurchase Program In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits. During 2014, the company purchased 41.5 million common shares for \$5.0 billion. From the inception of the program through 2014, the company had purchased 180.9 million shares for \$20.0 billion. Given the change in market conditions, the company is suspending the share repurchase program for 2015.

Capital and Exploratory Expenditures

Capital and exploratory expenditures by business segment for 2014, 2013 and 2012 are as follows:

Millions of dollars	2014			2013			2012		
	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream	\$ 8,799	\$ 28,316	\$37,115	\$ 8,480	\$ 29,378	\$37,858	\$ 8,531	\$ 21,913	\$30,444
Downstream	1,649	941	2,590	1,986	1,189	3,175	1,913	1,259	3,172
All Other	584	27	611	821	23	844	602	11	613
Total	\$ 11,032	\$ 29,284	\$40,316	\$ 11,287	\$ 30,590	\$41,877	\$ 11,046	\$ 23,183	\$34,229
Total, Excluding Equity in Affiliates	\$ 10,011	\$ 26,838	\$36,849	\$ 10,562	\$ 28,617	\$39,179	\$ 10,738	\$ 21,374	\$32,112

Total expenditures for 2014 were \$40.3 billion, including \$3.5 billion for the company's share of equity-affiliate expenditures, which did not require cash outlays by the company. In 2013 and 2012, expenditures were \$41.9 billion and \$34.2 billion, respectively, including the company's share of affiliates' expenditures of \$2.7 billion and \$2.1 billion, respectively. The increase in expenditures between 2013 and 2012 included approximately \$4 billion for major resource acquisitions in Argentina, Australia, the Permian Basin and the Kurdistan Region of Iraq, along with the additional acreage in the Duvernay Shale and interests in the Kitimat LNG Project. In addition, work progressed on a number of major capital projects, particularly two Australian LNG projects and two deepwater Gulf of Mexico projects.

Of the \$40.3 billion of expenditures in 2014, 92 percent, or \$37.1 billion, was related to upstream activities. Approximately 90 percent was expended for upstream operations in 2013 and 2012. International upstream accounted for 76 percent of the worldwide upstream investment in 2014, 78 percent in 2013 and 72 percent in 2012.

The company estimates that 2015 capital and exploratory expenditures will be \$35.0 billion, including \$4.0 billion of spending by affiliates. This planned reduction, compared to 2014 expenditures, is in large part a response to current market conditions. Approximately 90 percent of the total, or \$31.6 billion, is budgeted for exploration and production activities. Approximately \$23.4 billion, or 74 percent, of this amount is for projects outside the United States. Spending in 2015 is primarily focused on major development projects in Angola, Argentina, Australia, Canada, Kazakhstan, Nigeria, Republic of the Congo, Russia, the United Kingdom and the U.S. Also included is funding for enhancing recovery and mitigating natural field declines for currently-producing assets, development of shale and tight resources, and focused exploration and appraisal activities. The company will continue to monitor crude oil market conditions, and will further modify spending plans, as needed.

Worldwide downstream spending in 2015 is estimated at \$2.8 billion, with \$2.0 billion for projects in the United States. About half of these investments are expected to be funded by CPEM for petrochemicals projects in the United States. Additional capital outlays include projects at U.S. and international refineries.

Investments in technology companies and other corporate businesses in 2015 are budgeted at \$0.6 billion.

Noncontrolling Interests The company had noncontrolling interests of \$1.2 billion at December 31, 2014 compared to \$1.3 billion at year-end 2013. Distributions to noncontrolling interests totaled \$47 million and \$99 million in 2014 and 2013, respectively.

Pension Obligations Information related to pension plan contributions is included on page 64 in Note 22 to the Consolidated Financial Statements under the heading "Cash Contributions and Benefit Payments."

Financial Ratios

	2014	At December 31	
		2013	2012
Current Ratio	1.3	1.5	1.6
Interest Coverage Ratio	87.2	126.2	191.3
Debt Ratio	15.2 %	12.1 %	8.2 %

Current Ratio – current assets divided by current liabilities, which indicates the company's ability to repay its short-term liabilities with short-term assets. The current ratio in all periods was adversely affected by the fact that Chevron's inventories are valued on a last-in, first-out basis. At year-end 2014, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately \$8.1 billion.

Interest Coverage Ratio – income before income tax expense, plus interest and debt expense and amortization of capitalized interest, less net income attributable to noncontrolling interests, divided by before-tax interest costs. This ratio indicates the company's ability to pay interest on outstanding debt. The company's interest coverage ratio in 2014 was lower than 2013 and 2012 due to lower income.

Debt Ratio – total debt as a percentage of total debt plus Chevron Corporation Stockholders' Equity, which indicates the company's leverage. The company's debt ratio in 2014 was higher than 2013 and 2012 as the company took on more debt to finance its ongoing investment program, partially offset by a higher stockholders' equity balance.

Off-Balance-Sheet Arrangements, Contractual Obligations, Guarantees and Other Contingencies

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements

The company and its subsidiaries have certain contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2015 – \$3.6 billion; 2016 – \$3.0 billion; 2017 – \$2.3 billion; 2018 – \$2.1 billion; 2019 – \$1.6 billion; 2020 and after – \$4.5 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$3.7 billion in 2014, \$3.6 billion in 2013 and \$3.6 billion in 2012.

The following table summarizes the company's significant contractual obligations:

Millions of dollars	Total ¹	Payments Due by Period			
		2015	2016-2017	2018-2019	After 2019
On Balance Sheet: ²					
Short-Term Debt ³	\$ 3,790	\$ 3,790	\$ —	\$ —	\$ —
Long-Term Debt ³	23,960	—	13,200	4,650	6,110
Noncancelable Capital Lease Obligations	140	34	47	35	24
Interest	2,393	378	737	445	833
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	3,498	793	1,229	787	689
Throughput and Take-or-Pay Agreements ⁴	9,627	1,985	2,165	1,842	3,635
Other Unconditional Purchase Obligations ⁴	7,490	1,633	3,120	1,895	842

¹ Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 22 beginning on page 60.

² Does not include amounts related to the company's income tax liabilities associated with uncertain tax positions. The company is unable to make reasonable estimates of the periods in which such liabilities may become payable. The company does not expect settlement of such liabilities to have a material effect on its consolidated financial position or liquidity in any single period.

³ \$8.0 billion of short-term debt that the company expects to refinance is included in long-term debt. The repayment schedule above reflects the projected repayment of the entire amounts in the 2016–2017 period.

⁴ Does not include commodity purchase obligations that are not fixed or determinable. These obligations are generally monetized in a relatively short period of time through sales transactions or similar agreements with third parties. Examples include obligations to purchase LNG, regasified natural gas and refinery products at indexed prices.

Direct Guarantees

Millions of dollars	Commitment Expiration by Period				
	Total	2015	2016-2017	2018-2019	After 2019
Guarantee of nonconsolidated affiliate or joint-venture obligations	\$485	\$38	\$76	\$76	\$295

The company's guarantee of \$485 million is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 13-year remaining term of the guarantee, the maximum guarantee amount will be reduced as certain fees are paid by the affiliate. There are numerous cross-indemnity agreements with the affiliate and the other partners to permit recovery of amounts paid under the guarantee. Chevron has recorded no liability for its obligation under this guarantee.

Indemnifications Information related to indemnifications is included on page 65 in Note 23 to the Consolidated Financial Statements under the heading "Indemnifications."

Financial and Derivative Instrument Market Risk

The market risk associated with the company's portfolio of financial and derivative instruments is discussed below. The estimates of financial exposure to market risk do not represent the company's projection of future market changes. The actual impact of future market changes could differ materially due to factors discussed elsewhere in this report, including those set forth under the heading "Risk Factors" in Part I, Item 1A, of the company's 2014 Annual Report on Form 10-K.

Derivative Commodity Instruments Chevron is exposed to market risks related to the price volatility of crude oil, refined products, natural gas, natural gas liquids, liquefied natural gas and refinery feedstocks. The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. The company also uses derivative commodity instruments for limited trading purposes. The results of these activities were not material to the company's financial position, results of operations or cash flows in 2014.

The company's market exposure positions are monitored on a daily basis by an internal Risk Control group in accordance with the company's risk management policies, which are reviewed by the Audit Committee of the company's Board of Directors.

Derivatives beyond those designated as normal purchase and normal sale contracts are recorded at fair value on the Consolidated Balance Sheet with resulting gains and losses reflected in income. Fair values are derived principally from published market quotes and other independent third-party quotes. The change in fair value of Chevron's derivative commodity instruments in 2014 was not material to the company's results of operations.

The company uses the Monte Carlo simulation method with a 95 percent confidence level as its Value-at-Risk (VaR) model to estimate the maximum potential loss in fair value from the effect of adverse changes in market conditions on derivative commodity instruments held or issued. A one-day holding period is used on the assumption that market-risk positions can be liquidated or hedged within one day. Based on these inputs, the VaR for the company's primary risk exposures in the area of derivative commodity instruments at December 31, 2014 and 2013 was not material to the company's cash flows or results of operations.

Foreign Currency The company may enter into foreign currency derivative contracts to manage some of its foreign currency exposures. These exposures include revenue and anticipated purchase transactions, including foreign currency capital expenditures and lease commitments. The foreign currency derivative contracts, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. There were no open foreign currency derivative contracts at December 31, 2014.

Interest Rates The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. Interest rate swaps, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. At year-end 2014, the company had no interest rate swaps.

Transactions With Related Parties

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements and long-term purchase agreements. Refer to "Other Information" in Note 13 of the Consolidated Financial Statements, page 49, for further discussion. Management believes these agreements have been negotiated on terms consistent with those that would have been negotiated with an unrelated party.

Litigation and Other Contingencies

MTBE Information related to methyl tertiary butyl ether (MTBE) matters is included on page 50 in Note 15 to the Consolidated Financial Statements under the heading "MTBE."

Ecuador Information related to Ecuador matters is included in Note 15 to the Consolidated Financial Statements under the heading "Ecuador," beginning on page 50.

Environmental The following table displays the annual changes to the company's before-tax environmental remediation reserves, including those for federal Superfund sites and analogous sites under state laws.

<i>Millions of dollars</i>	2014	2013	2012
Balance at January 1	\$ 1,456	\$ 1,403	\$ 1,404
Net Additions	636	488	428
Expenditures	(409)	(435)	(429)
Balance at December 31	\$ 1,683	\$ 1,456	\$ 1,403

The company records asset retirement obligations when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. These asset retirement obligations include costs related to environmental issues. The liability balance of approximately \$15.1 billion for asset retirement obligations at year-end 2014 related primarily to upstream properties.

For the company's other ongoing operating assets, such as refineries and chemicals facilities, no provisions are made for exit or cleanup costs that may be required when such assets reach the end of their useful lives unless a decision to sell or otherwise abandon the facility has been made, as the indeterminate settlement dates for the asset retirements prevent estimation of the fair value of the asset retirement obligation.

Refer to the discussion below for additional information on environmental matters and their impact on Chevron, and on the company's 2014 environmental expenditures. Refer to Note 23 on pages 65 through 67 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 24 on page 67 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 20 to the Consolidated Financial Statements, Accounting for Suspended Exploratory Wells, beginning on page 57.

Income Taxes Information related to income tax contingencies is included on pages 53 through 56 in Note 16 and page 65 in Note 23 to the Consolidated Financial Statements under the heading "Income Taxes."

Other Contingencies Information related to other contingencies is included on page 66 in Note 23 to the Consolidated Financial Statements under the heading "Other Contingencies."

Environmental Matters

Virtually all aspects of the businesses in which the company engages are subject to various international, federal, state and local environmental, health and safety laws, regulations and market-based programs. These regulatory requirements continue to increase in both number and complexity over time and govern not only the manner in which the company conducts its operations, but also the products it sells. Regulations intended to address concerns about greenhouse gas emissions and global climate change also continue to evolve and include those at the international or multinational (such as the mechanisms under the Kyoto Protocol and the European Union's Emissions Trading System), national (such as the U.S. Environmental Protection Agency's emission standards and renewable transportation fuel content requirements or domestic market-based programs such as those in effect in Australia and New Zealand), and state or regional (such as California's Global Warming Solutions Act) levels. Regulations intended to address hydraulic fracturing also continue to evolve at the national and state levels.

Most of the costs of complying with laws and regulations pertaining to company operations and products are embedded in the normal costs of doing business. It is not possible to predict with certainty the amount of additional investments in new or existing facilities or amounts of incremental operating costs to be incurred in the future to: prevent, control, reduce or eliminate releases of hazardous materials into the environment; comply with existing and new environmental laws or regulations; or remediate and restore areas damaged by prior releases of hazardous materials. Although these costs may be significant to the results of operations in any single period, the company does not expect them to have a material effect on the company's liquidity or financial position.

Accidental leaks and spills requiring cleanup may occur in the ordinary course of business. In addition to the costs for environmental protection associated with its ongoing operations and products, the company may incur expenses for corrective actions at various owned and previously owned facilities and at third-party-owned waste disposal sites used by the company. An obligation may arise when operations are closed or sold or at non-Chevron sites where company products have been handled or disposed of. Most of the expenditures to fulfill these obligations relate to facilities and sites where past operations followed practices and procedures that were considered acceptable at the time but now require investigative or remedial work or both to meet current standards.

Using definitions and guidelines established by the American Petroleum Institute, Chevron estimated its worldwide environmental spending in 2014 at approximately \$2.6 billion for its consolidated companies. Included in these expenditures were approximately \$0.9 billion of environmental capital expenditures and \$1.7 billion of costs associated with the prevention, control, abatement or elimination of hazardous substances and pollutants from operating, closed or divested sites, and the abandonment and restoration of sites.

For 2015, total worldwide environmental capital expenditures are estimated at \$0.9 billion. These capital costs are in addition to the ongoing costs of complying with environmental regulations and the costs to remediate previously contaminated sites.

Critical Accounting Estimates and Assumptions

Management makes many estimates and assumptions in the application of generally accepted accounting principles (GAAP) that may have a material impact on the company's consolidated financial statements and related disclosures and on the comparability of such information over different reporting periods. Such estimates and assumptions affect reported amounts of assets, liabilities, revenues and expenses, as well as disclosures of contingent assets and liabilities. Estimates and assumptions are based on management's experience and other information available prior to the issuance of the financial statements. Materially different results can occur as circumstances change and additional information becomes known.

The discussion in this section of "critical" accounting estimates and assumptions is according to the disclosure guidelines of the Securities and Exchange Commission (SEC), wherein:

1. the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters, or the susceptibility of such matters to change; and
2. the impact of the estimates and assumptions on the company's financial condition or operating performance is material.

The development and selection of accounting estimates and assumptions, including those deemed "critical," and the associated disclosures in this discussion have been discussed by management with the Audit Committee of the Board of Directors. The areas of accounting and the associated "critical" estimates and assumptions made by the company are as follows:

Oil and Gas Reserves Crude oil and natural gas reserves are estimates of future production that impact certain asset and expense accounts included in the Consolidated Financial Statements. Proved reserves are the estimated quantities of oil and gas that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in the future under existing economic conditions, operating methods and government regulations. Proved reserves include both developed and undeveloped volumes. Proved developed reserves represent volumes expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled proved acreage, or from existing wells where a relatively major expenditure is required for recompletion. Variables impacting Chevron's estimated volumes of crude oil and natural gas reserves include field performance, available technology, commodity prices, and development and production costs.

The estimates of crude oil and natural gas reserves are important to the timing of expense recognition for costs incurred and to the valuation of certain oil and gas producing assets. Impacts of oil and gas reserves on Chevron's Consolidated Financial Statements, using the successful efforts method of accounting, include the following:

1. Amortization - Capitalized exploratory drilling and development costs are depreciated on a unit-of-production (UOP) basis using proved developed reserves. Acquisition costs of proved properties are amortized on a UOP basis using total proved reserves. During 2014, Chevron's UOP Depreciation, Depletion and Amortization (DD&A) for oil and gas properties was \$13.0 billion, and proved developed reserves at the beginning of 2014 were 4.8 billion barrels for consolidated companies. If the estimates of proved reserves used in the UOP calculations for consolidated operations had been lower by 5 percent across all oil and gas properties, UOP DD&A in 2014 would have increased by approximately \$690 million.

2. Impairment - Oil and gas reserves are used in assessing oil and gas producing properties for impairment. A significant reduction in the estimated reserves of a property would trigger an impairment review. In assessing whether the property is impaired, the fair value of the property must be determined. Frequently, a discounted cash flow methodology is the best estimate of fair value. Proved reserves (and, in some cases, a portion of unproved resources) are used to estimate future production volumes in the cash flow model. For a further discussion of estimates and assumptions used in impairment assessments, see *Impairment of Properties, Plant and Equipment and Investments in Affiliates* below.

Refer to Table V, "Reserve Quantity Information," beginning on page 74, for the changes in proved reserve estimates for the three years ending December 31, 2014, and to Table VII, "Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves" on page 80 for estimates of proved reserve values for each of the three years ended December 31, 2014.

This Oil and Gas Reserves commentary should be read in conjunction with the Properties, Plant and Equipment section of Note 1 to the Consolidated Financial Statements, beginning on page 36, which includes a description of the "successful efforts" method of accounting for oil and gas exploration and production activities.

Impairment of Properties, Plant and Equipment and Investments in Affiliates The company assesses its properties, plant and equipment (PP&E) for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge is recorded for the excess of carrying value of the asset over its estimated fair value.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters, such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles, and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas, commodity chemicals and refined products. However, the impairment reviews and calculations are based on assumptions that are consistent with the company's business plans and long-term investment decisions. Refer also to the discussion of impairments of properties, plant and equipment in Note 9 beginning on page 42 and to the section on Properties, Plant and Equipment in Note 1, "Summary of Significant Accounting Policies," beginning on page 36.

The company routinely performs impairment reviews when triggering events arise to determine whether any write-down in the carrying value of an asset or asset group is required. For example, when significant downward revisions to crude oil and natural gas reserves are made for any single field or concession, an impairment review is performed to determine if the carrying value of the asset remains recoverable. Similarly, a significant downward revision in the company's crude oil or natural gas price outlook would trigger impairment reviews for impacted upstream assets. Also, if the expectation of sale of a particular asset or asset group in any period has been deemed more likely than not, an impairment review is performed, and if the estimated net proceeds exceed the carrying value of the asset or asset group, no impairment charge is required. Such calculations are reviewed each period until the asset or asset group is disposed of. Assets that are not impaired on a held-and-used basis could possibly become impaired if a decision is made to sell such assets. That is, the assets would be impaired if they are classified as held-for-sale and the estimated proceeds from the sale, less costs to sell, are less than the assets' associated carrying values.

Investments in common stock of affiliates that are accounted for under the equity method, as well as investments in other securities of these equity investees, are reviewed for impairment when the fair value of the investment falls below the company's carrying value. Differing assumptions could affect whether an investment is impaired in any period or the amount of the impairment, and are not subject to sensitivity analysis.

No material individual impairments of PP&E or Investments were recorded for the three years ending December 31, 2014. A sensitivity analysis of the impact on earnings for these periods if other assumptions had been used in impairment reviews and impairment calculations is not practicable, given the broad range of the company's PP&E and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions might have avoided the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired.

Asset Retirement Obligations In the determination of fair value for an asset retirement obligation (ARO), the company uses various assumptions and judgments, including such factors as the existence of a legal obligation, estimated amounts and timing of settlements, discount and inflation rates, and the expected impact of advances in technology and process improvements. A sensitivity analysis of the ARO impact on earnings for 2014 is not practicable, given the broad range of the company's long-lived assets and the number of assumptions involved in the estimates. That is, favorable changes to some

assumptions would have reduced estimated future obligations, thereby lowering accretion expense and amortization costs, whereas unfavorable changes would have the opposite effect. Refer to Note 24 on page 67 for additional discussions on asset retirement obligations.

Pension and Other Postretirement Benefit Plans Note 22, beginning on page 60, includes information on the funded status of the company's pension and other postretirement benefit (OPEB) plans reflected on the Consolidated Balance Sheet; the components of pension and OPEB expense reflected on the Consolidated Statement of Income; and the related underlying assumptions.

The determination of pension plan expense and obligations is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. Critical assumptions in determining expense and obligations for OPEB plans, which provide for certain health care and life insurance benefits for qualifying retired employees and which are not funded, are the discount rate and the assumed health care cost-trend rates. Information related to the Company's processes to develop these assumptions is included on page 62 in Note 22 under the relevant headings. Actual rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

For 2014, the company used an expected long-term rate of return of 7.5 percent and a discount rate of 4.3 percent for U.S. pension plans. For the 10 years ending December 31, 2014, actual asset returns averaged 6.0 percent for the plan. The actual return for 2014 was more than 7.5 percent. Additionally, with the exception of two years within this 10-year period, actual asset returns for this plan equaled or exceeded 7.5 percent during each year.

Total pension expense for 2014 was \$1.2 billion. An increase in the expected long-term return on plan assets or the discount rate would reduce pension plan expense, and vice versa. As an indication of the sensitivity of pension expense to the long-term rate of return assumption, a 1 percent increase in this assumption for the company's primary U.S. pension plan, which accounted for about 39 percent of companywide pension expense, would have reduced total pension plan expense for 2014 by approximately \$98 million. A 1 percent increase in the discount rate for this same plan would have reduced pension expense for 2014 by approximately \$229 million.

The aggregate funded status recognized at December 31, 2014, was a net liability of approximately \$4.7 billion. An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan. At December 31, 2014, the company used a discount rate of 3.7 percent to measure the obligations for the U.S. pension plans. As an indication of the sensitivity of pension liabilities to the discount rate assumption, a 0.25 percent increase in the discount rate applied to the company's primary U.S. pension plan, which accounted for about 63 percent of the companywide pension obligation, would have reduced the plan obligation by approximately \$403 million, which would have decreased the plan's underfunded status from approximately \$1.6 billion to \$1.2 billion.

For the company's OPEB plans, expense for 2014 was \$219 million, and the total liability, which reflected the unfunded status of the plans at the end of 2014, was \$3.7 billion. For the main U.S. OPEB plan, the company used a 4.7 percent discount rate to measure expense in 2014, and a 4.1 percent discount rate to measure the benefit obligations at December 31, 2014. Discount rate changes, similar to those used in the pension sensitivity analysis, resulted in an immaterial impact on 2014 OPEB expense and OPEB liabilities at the end of 2014. For information on the sensitivity of the health care cost-trend rate, refer to 62 in Note 22 under the heading "Other Benefit Assumptions."

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are included in actuarial gain/loss. Refer to page 61 in Note 22 for a description of the method used to amortize the \$7.2 billion of before-tax actuarial losses recorded by the company as of December 31, 2014, and an estimate of the costs to be recognized in expense during 2015. In addition, information related to company contributions is included on page 64 in Note 22 under the heading "Cash Contributions and Benefit Payments."

Contingent Losses Management also makes judgments and estimates in recording liabilities for claims, litigation, tax matters and environmental remediation. Actual costs can frequently vary from estimates for a variety of reasons. For example, the costs for settlement of claims and litigation can vary from estimates based on differing interpretations of laws, opinions on culpability and assessments on the amount of damages. Similarly, liabilities for environmental remediation are subject to change because of changes in laws, regulations and their interpretation, the determination of additional information on the extent and nature of site contamination, and improvements in technology.

Under the accounting rules, a liability is generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as "Operating expenses" or "Selling,

general and administrative expenses” on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is “more likely than not” (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 23 beginning on page 65. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, environmental remediation and tax matters for the three years ended December 31, 2014.

An estimate as to the sensitivity to earnings for these periods if other assumptions had been used in recording these liabilities is not practicable because of the number of contingencies that must be assessed, the number of underlying assumptions and the wide range of reasonably possible outcomes, both in terms of the probability of loss and the estimates of such loss.

New Accounting Standards

Refer to Note 19, on page 57 in the Notes to Consolidated Financial Statements, for information regarding new accounting standards.

Quarterly Results and Stock Market Data

Unaudited

<i>Millions of dollars, except per-share amounts</i>	2014				2013			
	4th Q	3rd Q	2nd Q	1st Q	4th Q	3rd Q	2nd Q	1st Q
Revenues and Other Income								
Sales and other operating revenues ¹	\$42,111	\$51,822	\$55,583	\$50,978	\$53,950	\$56,603	\$55,307	\$54,296
Income from equity affiliates	1,555	1,912	1,709	1,922	1,824	1,635	1,784	2,284
Other income	2,422	945	646	365	384	265	278	238
Total Revenues and Other Income	46,088	54,679	57,938	53,265	56,158	58,503	57,369	56,818
Costs and Other Deductions								
Purchased crude oil and products	24,263	30,741	33,844	30,823	32,691	34,822	34,273	32,910
Operating expenses	6,572	6,403	6,287	6,023	6,521	6,066	6,278	5,762
Selling, general and administrative expenses	1,368	1,122	1,077	927	1,176	1,197	1,139	998
Exploration expenses	510	366	694	415	726	559	329	247
Depreciation, depletion and amortization	4,873	3,948	3,842	4,130	3,635	3,658	3,412	3,481
Taxes other than on income ¹	3,118	3,236	3,167	3,019	3,211	3,366	3,349	3,137
Total Costs and Other Deductions	40,704	45,816	48,911	45,337	47,960	49,668	48,780	46,535
Income Before Income Tax Expense	5,384	8,863	9,027	7,928	8,198	8,835	8,589	10,283
Income Tax Expense	1,912	3,236	3,337	3,407	3,240	3,839	3,185	4,044
Net Income	\$ 3,472	\$ 5,627	\$ 5,690	\$ 4,521	\$ 4,958	\$ 4,996	\$ 5,404	\$ 6,239
Less: Net income attributable to noncontrolling interests	1	34	25	9	28	46	39	61
Net Income Attributable to Chevron Corporation	\$ 3,471	\$ 5,593	\$ 5,665	\$ 4,512	\$ 4,930	\$ 4,950	\$ 5,365	\$ 6,178
Per Share of Common Stock								
Net Income Attributable to Chevron Corporation								
– Basic	\$ 1.86	\$ 2.97	\$ 3.00	\$ 2.38	\$ 2.60	\$ 2.58	\$ 2.80	\$ 3.20
– Diluted	\$ 1.85	\$ 2.95	\$ 2.98	\$ 2.36	\$ 2.57	\$ 2.57	\$ 2.77	\$ 3.18
Dividends	\$ 1.07	\$ 1.07	\$ 1.07	\$ 1.00	\$ 1.00	\$ 1.00	\$ 1.00	\$ 0.90
Common Stock Price Range – High²	\$120.17	\$135.10	\$133.57	\$125.32	\$125.65	\$127.83	\$127.40	\$121.56
– Low ²	\$100.15	\$118.66	\$116.50	\$109.27	\$114.44	\$117.22	\$114.12	\$108.74
¹ Includes excise, value-added and similar taxes:	\$ 2,004	\$ 2,116	\$ 2,120	\$ 1,946	\$ 2,128	\$ 2,223	\$ 2,108	\$ 2,033
² Intraday price.								

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 9, 2015, stockholders of record numbered approximately 152,000. There are no restrictions on the company's ability to pay dividends.

Management's Responsibility for Financial Statements

To the Stockholders of Chevron Corporation

Management of Chevron is responsible for preparing the accompanying consolidated financial statements and the related information appearing in this report. The statements were prepared in accordance with accounting principles generally accepted in the United States of America and fairly represent the transactions and financial position of the company. The financial statements include amounts that are based on management's best estimates and judgments.

As stated in its report included herein, the independent registered public accounting firm of PricewaterhouseCoopers LLP has audited the company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Board of Directors of Chevron has an Audit Committee composed of directors who are not officers or employees of the company. The Audit Committee meets regularly with members of management, the internal auditors and the independent registered public accounting firm to review accounting, internal control, auditing and financial reporting matters. Both the internal auditors and the independent registered public accounting firm have free and direct access to the Audit Committee without the presence of management.

Management's Report on Internal Control Over Financial Reporting

The company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). The company's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the company's internal control over financial reporting based on the *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the results of this evaluation, the company's management concluded that internal control over financial reporting was effective as of December 31, 2014.

On May 14, 2013, COSO published an updated *Internal Control - Integrated Framework* (2013) and related illustrative documents. The company adopted the new framework effective January 1, 2014.

The effectiveness of the company's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.



John S. Watson
Chairman of the Board
and Chief Executive Officer



Patricia E. Yarrington
Vice President
and Chief Financial Officer



Matthew J. Foehr
Vice President
and Comptroller

February 20, 2015

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Chevron Corporation:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, comprehensive income, equity and of cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2014, and December 31, 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, 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 opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

San Francisco, California

February 20, 2015

Consolidated Statement of Income
Millions of dollars, except per-share amounts

	Year ended December 31		
	2014	2013	2012
Revenues and Other Income			
Sales and other operating revenues*	\$ 200,494	\$ 220,156	\$ 230,590
Income from equity affiliates	7,098	7,527	6,889
Other income	4,378	1,165	4,430
Total Revenues and Other Income	211,970	228,848	241,909
Costs and Other Deductions			
Purchased crude oil and products	119,671	134,696	140,766
Operating expenses	25,285	24,627	22,570
Selling, general and administrative expenses	4,494	4,510	4,724
Exploration expenses	1,985	1,861	1,728
Depreciation, depletion and amortization	16,793	14,186	13,413
Taxes other than on income*	12,540	13,063	12,376
Total Costs and Other Deductions	180,768	192,943	195,577
Income Before Income Tax Expense	31,202	35,905	46,332
Income Tax Expense	11,892	14,308	19,996
Net Income	19,310	21,597	26,336
Less: Net income attributable to noncontrolling interests	69	174	157
Net Income Attributable to Chevron Corporation	\$ 19,241	\$ 21,423	\$ 26,179
Per Share of Common Stock			
Net Income Attributable to Chevron Corporation			
– Basic	\$ 10.21	\$ 11.18	\$ 13.42
– Diluted	\$ 10.14	\$ 11.09	\$ 13.32
* Includes excise, value-added and similar taxes.	\$ 8,186	\$ 8,492	\$ 8,010

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income
Millions of dollars

	Year ended December 31		
	2014	2013	2012
Net Income	\$ 19,310	\$ 21,597	\$ 26,336
Currency translation adjustment			
Unrealized net change arising during period	(73)	42	23
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	(2)	(7)	1
Derivatives			
Net derivatives (loss) gain on hedge transactions	(66)	(111)	20
Reclassification to net income of net realized (gain) loss	(17)	(1)	(14)
Income taxes on derivatives transactions	29	39	(3)
Total	(54)	(73)	3
Defined benefit plans			
Actuarial gain (loss)			
Amortization to net income of net actuarial loss and settlements	757	866	920
Actuarial (loss) gain arising during period	(2,730)	3,379	(1,180)
Prior service credits (cost)			
Amortization to net income of net prior service costs (credits)	26	(27)	(61)
Prior service (costs) credits arising during period	(6)	60	(142)
Defined benefit plans sponsored by equity affiliates	(99)	164	(54)
Income taxes on defined benefit plans	901	(1,614)	143
Total	(1,151)	2,828	(374)
Other Comprehensive (Loss) Gain, Net of Tax	(1,280)	2,790	(347)
Comprehensive Income	18,030	24,387	25,989
Comprehensive income attributable to noncontrolling interests	(69)	(174)	(157)
Comprehensive Income Attributable to Chevron Corporation	\$ 17,961	\$ 24,213	\$ 25,832

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

Millions of dollars, except per-share amount

	At December 31	
	2014	2013
Assets		
Cash and cash equivalents	\$ 12,785	\$ 16,245
Time deposits	8	8
Marketable securities	422	263
Accounts and notes receivable (less allowance: 2014 - \$59; 2013 - \$62)	16,736	21,622
Inventories:		
Crude oil and petroleum products	3,854	3,879
Chemicals	467	491
Materials, supplies and other	2,184	2,010
Total inventories	6,505	6,380
Prepaid expenses and other current assets	5,776	5,732
Total Current Assets	42,232	50,250
Long-term receivables, net	2,817	2,833
Investments and advances	26,912	25,502
Properties, plant and equipment, at cost	327,289	296,433
Less: Accumulated depreciation, depletion and amortization	144,116	131,604
Properties, plant and equipment, net	183,173	164,829
Deferred charges and other assets	6,299	5,120
Goodwill	4,593	4,639
Assets held for sale	—	580
Total Assets	\$ 266,026	\$ 253,753
Liabilities and Equity		
Short-term debt	\$ 3,790	\$ 374
Accounts payable	19,000	22,815
Accrued liabilities	5,328	5,402
Federal and other taxes on income	2,575	3,092
Other taxes payable	1,233	1,335
Total Current Liabilities	31,926	33,018
Long-term debt	23,960	19,960
Capital lease obligations	68	97
Deferred credits and other noncurrent obligations	23,549	22,982
Noncurrent deferred income taxes	21,920	21,301
Noncurrent employee benefit plans	8,412	5,968
Total Liabilities	109,835	103,326
Preferred stock (authorized 100,000,000 shares; \$1.00 par value; none issued)	—	—
Common stock (authorized 6,000,000,000 shares; \$0.75 par value; 2,442,676,580 shares issued at December 31, 2014 and 2013)	1,832	1,832
Capital in excess of par value	16,041	15,713
Retained earnings	184,987	173,677
Accumulated other comprehensive loss	(4,859)	(3,579)
Deferred compensation and benefit plan trust	(240)	(240)
Treasury stock, at cost (2014 - 563,027,772 shares; 2013 - 529,073,512 shares)	(42,733)	(38,290)
Total Chevron Corporation Stockholders' Equity	155,028	149,113
Noncontrolling interests	1,163	1,314
Total Equity	156,191	150,427
Total Liabilities and Equity	\$ 266,026	\$ 253,753

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2014	2013	2012
Operating Activities			
Net Income	\$ 19,310	\$ 21,597	\$ 26,336
Adjustments			
Depreciation, depletion and amortization	16,793	14,186	13,413
Dry hole expense	875	683	555
Distributions less than income from equity affiliates	(2,202)	(1,178)	(1,351)
Net before-tax gains on asset retirements and sales	(3,540)	(639)	(4,089)
Net foreign currency effects	(277)	(103)	207
Deferred income tax provision	1,572	1,876	2,015
Net (increase) decrease in operating working capital	(540)	(1,331)	363
(Increase) decrease in long-term receivables	(9)	183	(169)
Decrease (increase) in other deferred charges	263	(321)	1,047
Cash contributions to employee pension plans	(392)	(1,194)	(1,228)
Other	(378)	1,243	1,713
Net Cash Provided by Operating Activities	31,475	35,002	38,812
Investing Activities			
Capital expenditures	(35,407)	(37,985)	(30,938)
Proceeds and deposits related to asset sales	5,729	1,143	2,777
Net sales of time deposits	—	700	3,250
Net (purchases) sales of marketable securities	(148)	3	(3)
Net repayment of loans by equity affiliates	140	314	328
Net (purchases) sales of other short-term investments	(207)	216	(210)
Net Cash Used for Investing Activities	(29,893)	(35,609)	(24,796)
Financing Activities			
Net borrowings of short-term obligations	3,431	2,378	264
Proceeds from issuances of long-term debt	4,000	6,000	4,007
Repayments of long-term debt and other financing obligations	(43)	(132)	(2,224)
Cash dividends - common stock	(7,928)	(7,474)	(6,844)
Distributions to noncontrolling interests	(47)	(99)	(41)
Net purchases of treasury shares	(4,412)	(4,494)	(4,142)
Net Cash Used for Financing Activities	(4,999)	(3,821)	(8,980)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(43)	(266)	39
Net Change in Cash and Cash Equivalents	(3,460)	(4,694)	5,075
Cash and Cash Equivalents at January 1	16,245	20,939	15,864
Cash and Cash Equivalents at December 31	\$ 12,785	\$ 16,245	\$ 20,939

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	2014		2013		2012	
	Shares	Amount	Shares	Amount	Shares	Amount
Preferred Stock	—	\$ —	—	\$ —	—	\$ —
Common Stock	2,442,677	\$ 1,832	2,442,677	\$ 1,832	2,442,677	\$ 1,832
Capital in Excess of Par						
Balance at January 1		\$ 15,713		\$ 15,497		\$ 15,156
Treasury stock transactions		328		216		341
Balance at December 31		\$ 16,041		\$ 15,713		\$ 15,497
Retained Earnings						
Balance at January 1		\$ 173,677		\$ 159,730		\$ 140,399
Net income attributable to Chevron Corporation		19,241		21,423		26,179
Cash dividends on common stock		(7,928)		(7,474)		(6,844)
Stock dividends		(3)		(3)		(3)
Tax (charge) benefit from dividends paid on unallocated ESOP shares and other		—		1		(1)
Balance at December 31		\$ 184,987		\$ 173,677		\$ 159,730
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		\$ (23)		\$ (65)		\$ (88)
Change during year		(73)		42		23
Balance at December 31		\$ (96)		\$ (23)		\$ (65)
Unrealized net holding (loss) gain on securities						
Balance at January 1		\$ (6)		\$ 1		\$ —
Change during year		(2)		(7)		1
Balance at December 31		\$ (8)		\$ (6)		\$ 1
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		\$ 52		\$ 125		\$ 122
Change during year		(54)		(73)		3
Balance at December 31		\$ (2)		\$ 52		\$ 125
Pension and other postretirement benefit plans						
Balance at January 1		\$ (3,602)		\$ (6,430)		\$ (6,056)
Change during year		(1,151)		2,828		(374)
Balance at December 31		\$ (4,753)		\$ (3,602)		\$ (6,430)
Balance at December 31		\$ (4,859)		\$ (3,579)		\$ (6,369)
Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		\$ —		\$ (42)		\$ (58)
Net reduction of ESOP debt and other		—		42		16
Balance at December 31		\$ —		\$ —		\$ (42)
Benefit Plan Trust (Common Stock)	14,168	(240)	14,168	(240)	14,168	(240)
Balance at December 31	14,168	\$ (240)	14,168	\$ (240)	14,168	\$ (282)
Treasury Stock at Cost						
Balance at January 1	529,074	\$ (38,290)	495,979	\$ (33,884)	461,510	\$ (29,685)
Purchases	41,592	(5,006)	41,676	(5,004)	46,669	(5,004)
Issuances - mainly employee benefit plans	(7,638)	563	(8,581)	598	(12,200)	805
Balance at December 31	563,028	\$ (42,733)	529,074	\$ (38,290)	495,979	\$ (33,884)
Total Chevron Corporation Stockholders' Equity at December 31		\$ 155,028		\$ 149,113		\$ 136,524
Noncontrolling Interests		\$ 1,163		\$ 1,314		\$ 1,308
Total Equity		\$ 156,191		\$ 150,427		\$ 137,832

See accompanying Notes to the Consolidated Financial Statements.

Note 1

Summary of Significant Accounting Policies

General The company's Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in the United States of America. These require the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Although the company uses its best estimates and judgments, actual results could differ from these estimates as future confirming events occur.

Subsidiary and Affiliated Companies The Consolidated Financial Statements include the accounts of controlled subsidiary companies more than 50 percent-owned and any variable-interest entities in which the company is the primary beneficiary. Undivided interests in oil and gas joint ventures and certain other assets are consolidated on a proportionate basis. Investments in and advances to affiliates in which the company has a substantial ownership interest of approximately 20 percent to 50 percent, or for which the company exercises significant influence but not control over policy decisions, are accounted for by the equity method. As part of that accounting, the company recognizes gains and losses that arise from the issuance of stock by an affiliate that results in changes in the company's proportionate share of the dollar amount of the affiliate's equity currently in income.

Investments in affiliates are assessed for possible impairment when events indicate that the fair value of the investment may be below the company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in net income. In making the determination as to whether a decline is other than temporary, the company considers such factors as the duration and extent of the decline, the investee's financial performance, and the company's ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the investment's market value. The new cost basis of investments in these equity investees is not changed for subsequent recoveries in fair value.

Differences between the company's carrying value of an equity investment and its underlying equity in the net assets of the affiliate are assigned to the extent practicable to specific assets and liabilities based on the company's analysis of the various factors giving rise to the difference. When appropriate, the company's share of the affiliate's reported earnings is adjusted quarterly to reflect the difference between these allocated values and the affiliate's historical book values.

Derivatives The majority of the company's activity in derivative commodity instruments is intended to manage the financial risk posed by physical transactions. For some of this derivative activity, generally limited to large, discrete or infrequently occurring transactions, the company may elect to apply fair value or cash flow hedge accounting. For other similar derivative instruments, generally because of the short-term nature of the contracts or their limited use, the company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in current income. For the company's commodity trading activity, gains and losses from derivative instruments are reported in current income. The company may enter into interest rate swaps from time to time as part of its overall strategy to manage the interest rate risk on its debt. Interest rate swaps related to a portion of the company's fixed-rate debt, if any, may be accounted for as fair value hedges. Interest rate swaps related to floating-rate debt, if any, are recorded at fair value on the balance sheet with resulting gains and losses reflected in income. Where Chevron is a party to master netting arrangements, fair value receivable and payable amounts recognized for derivative instruments executed with the same counterparty are generally offset on the balance sheet.

Short-Term Investments All short-term investments are classified as available for sale and are in highly liquid debt securities. Those investments that are part of the company's cash management portfolio and have original maturities of three months or less are reported as "Cash equivalents." Bank time deposits with maturities greater than 90 days are reported as "Time deposits." The balance of short-term investments is reported as "Marketable securities" and is marked-to-market, with any unrealized gains or losses included in "Other comprehensive income."

Inventories Crude oil, petroleum products and chemicals inventories are generally stated at cost, using a last-in, first-out method. In the aggregate, these costs are below market. "Materials, supplies and other" inventories generally are stated at average cost.

Properties, Plant and Equipment The successful efforts method is used for crude oil and natural gas exploration and production activities. All costs for development wells, related plant and equipment, proved mineral interests in crude oil and natural gas properties, and related asset retirement obligation (ARO) assets are capitalized. Costs of exploratory wells are capitalized pending determination of whether the wells found proved reserves. Costs of wells that are assigned proved reserves remain capitalized.

Costs also are capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 20, beginning on page 57, for additional discussion of accounting for suspended exploratory well costs.

Long-lived assets to be held and used, including proved crude oil and natural gas properties, are assessed for possible impairment by comparing their carrying values with their associated undiscounted, future net before-tax cash flows. Events that can trigger assessments for possible impairments include write-downs of proved reserves based on field performance, significant decreases in the market value of an asset (including changes to the commodity price forecast), significant change in the extent or manner of use of or a physical change in an asset, and a more-likely-than-not expectation that a long-lived asset or asset group will be sold or otherwise disposed of significantly sooner than the end of its previously estimated useful life. Impaired assets are written down to their estimated fair values, generally their discounted, future net before-tax cash flows. For proved crude oil and natural gas properties in the United States, the company generally performs an impairment review on an individual field basis. Outside the United States, reviews are performed on a country, concession, development area or field basis, as appropriate. In Downstream, impairment reviews are performed on the basis of a refinery, a plant, a marketing/lubricants area or distribution area, as appropriate. Impairment amounts are recorded as incremental "Depreciation, depletion and amortization" expense.

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value. Refer to Note 9, beginning on page 42, relating to fair value measurements.

The fair value of a liability for an ARO is recorded as an asset and a liability when there is a legal obligation associated with the retirement of a long-lived asset and the amount can be reasonably estimated. Refer also to Note 24, on page 67, relating to AROs.

Depreciation and depletion of all capitalized costs of proved crude oil and natural gas producing properties, except mineral interests, are expensed using the unit-of-production method, generally by individual field, as the proved developed reserves are produced. Depletion expenses for capitalized costs of proved mineral interests are recognized using the unit-of-production method by individual field as the related proved reserves are produced. Periodic valuation provisions for impairment of capitalized costs of unproved mineral interests are expensed.

The capitalized costs of all other plant and equipment are depreciated or amortized over their estimated useful lives. In general, the declining-balance method is used to depreciate plant and equipment in the United States; the straight-line method is generally used to depreciate international plant and equipment and to amortize all capitalized leased assets.

Gains or losses are not recognized for normal retirements of properties, plant and equipment subject to composite group amortization or depreciation. Gains or losses from abnormal retirements are recorded as expenses, and from sales as "Other income."

Expenditures for maintenance (including those for planned major maintenance projects), repairs and minor renewals to maintain facilities in operating condition are generally expensed as incurred. Major replacements and renewals are capitalized.

Goodwill Goodwill resulting from a business combination is not subject to amortization. The company tests such goodwill at the reporting unit level for impairment on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

Environmental Expenditures Environmental expenditures that relate to ongoing operations or to conditions caused by past operations are expensed. Expenditures that create future benefits or contribute to future revenue generation are capitalized.

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For the company's U.S. and Canadian marketing facilities, the accrual is based in part on the probability that a future remediation commitment will be required. For crude oil, natural gas and mineral-producing properties, a liability for an ARO is made in accordance with accounting standards for asset retirement and environmental obligations. Refer to Note 24, on page 67, for a discussion of the company's AROs.

For federal Superfund sites and analogous sites under state laws, the company records a liability for its designated share of the probable and estimable costs, and probable amounts for other potentially responsible parties when mandated by the regulatory agencies because the other parties are not able to pay their respective shares.

The gross amount of environmental liabilities is based on the company's best estimate of future costs using currently available technology and applying current regulations and the company's own internal environmental policies. Future amounts are not discounted. Recoveries or reimbursements are recorded as assets when receipt is reasonably assured.

Currency Translation The U.S. dollar is the functional currency for substantially all of the company's consolidated operations and those of its equity affiliates. For those operations, all gains and losses from currency remeasurement are included in current period income. The cumulative translation effects for those few entities, both consolidated and affiliated, using functional currencies other than the U.S. dollar are included in "Currency translation adjustment" on the Consolidated Statement of Equity.

Revenue Recognition Revenues associated with sales of crude oil, natural gas, petroleum and chemicals products, and all other sources are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. Revenues from natural gas production from properties in which Chevron has an interest with other producers are generally recognized using the entitlement method. Excise, value-added and similar taxes assessed by a governmental authority on a revenue-producing transaction between a seller and a customer are presented on a gross basis. The associated amounts are shown as a footnote to the Consolidated Statement of Income, on page 31. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in "Purchased crude oil and products" on the Consolidated Statement of Income.

Stock Options and Other Share-Based Compensation The company issues stock options and other share-based compensation to certain employees. For equity awards, such as stock options, total compensation cost is based on the grant date fair value, and for liability awards, such as stock appreciation rights, total compensation cost is based on the settlement value. The company recognizes stock-based compensation expense for all awards over the service period required to earn the award, which is the shorter of the vesting period or the time period an employee becomes eligible to retain the award at retirement. Stock options and stock appreciation rights granted under the company's Long-Term Incentive Plan have graded vesting provisions by which one-third of each award vests on the first, second and third anniversaries of the date of grant. The company amortizes these graded awards on a straight-line basis.

Note 2

Changes in Accumulated Other Comprehensive Losses

The change in Accumulated Other Comprehensive Losses (AOCL) presented on the Consolidated Balance Sheet and the impact of significant amounts reclassified from AOCL on information presented in the Consolidated Statement of Income for the year ending December 31, 2014, are reflected in the table below.

	Year Ended December 31, 2014 ¹				
	Currency Translation Adjustment	Unrealized Holding Gains (Losses) on Securities	Derivatives	Defined Benefit Plans	Total
Balance at January 1	\$ (23)	\$ (6)	\$ 52	\$ (3,602)	\$ (3,579)
Components of Other Comprehensive Income (Loss):					
Before Reclassifications	(73)	(2)	(43)	(1,689)	(1,807)
Reclassifications ²	—	—	(11)	538	527
Net Other Comprehensive Income (Loss)	(73)	(2)	(54)	(1,151)	(1,280)
Balance at December 31	\$ (96)	\$ (8)	\$ (2)	\$ (4,753)	\$ (4,859)

¹ All amounts are net of tax.

² Refer to Note 22, Employee Benefit Plans for reclassified components totaling \$783 that are included in employee benefit costs for the year ending December 31, 2014. Related income taxes for the same period, totaling \$245, are reflected in Income Tax Expense on the Consolidated Statement of Income. All other reclassified amounts were insignificant.

Note 3**Noncontrolling Interests**

Ownership interests in the company's subsidiaries held by parties other than the parent are presented separately from the parent's equity on the Consolidated Balance Sheet. The amount of consolidated net income attributable to the parent and the noncontrolling interests are both presented on the face of the Consolidated Statement of Income. The term "earnings" is defined as "Net Income Attributable to Chevron Corporation."

Activity for the equity attributable to noncontrolling interests for 2014, 2013 and 2012 is as follows:

	2014	2013	2012
Balance at January 1	\$ 1,314	\$ 1,308	\$ 799
Net income	69	174	157
Distributions to noncontrolling interests	(47)	(99)	(41)
Other changes, net	(173)	(69)	393
Balance at December 31	\$ 1,163	\$ 1,314	\$ 1,308

Note 4**Information Relating to the Consolidated Statement of Cash Flows**

	Year ended December 31		
	2014	2013	2012
Net (increase) decrease in operating working capital was composed of the following:			
Decrease (increase) in accounts and notes receivable	\$ 4,491	\$ (1,101)	\$ 1,153
Increase in inventories	(146)	(237)	(233)
(Increase) decrease in prepaid expenses and other current assets	(407)	834	(471)
(Decrease) increase in accounts payable and accrued liabilities	(3,737)	160	544
Decrease in income and other taxes payable	(741)	(987)	(630)
Net (increase) decrease in operating working capital	\$ (540)	\$ (1,331)	\$ 363
Net cash provided by operating activities includes the following cash payments for income taxes:			
Income taxes	\$ 10,562	\$ 12,898	\$ 17,334
Net (purchases) sales of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	\$ (162)	\$ (7)	\$ (35)
Marketable securities sold	14	10	32
Net (purchases) sales of marketable securities	\$ (148)	\$ 3	\$ (3)
Net sales of time deposits consisted of the following gross amounts:			
Time deposits purchased	\$ (317)	\$ (2,317)	\$ (717)
Time deposits matured	317	3,017	3,967
Net sales of time deposits	\$ —	\$ 700	\$ 3,250

The "Net (increase) decrease in operating working capital" includes reductions of \$58, \$79 and \$98 for excess income tax benefits associated with stock options exercised during 2014, 2013 and 2012, respectively. These amounts are offset by an equal amount in "Net purchases of treasury shares." "Other" includes changes in postretirement benefits obligations and other long-term liabilities.

The "Net purchases of treasury shares" represents the cost of common shares acquired less the cost of shares issued for share-based compensation plans. Purchases totaled \$5,006, \$5,004 and \$5,004 in 2014, 2013 and 2012, respectively. In 2014, 2013 and 2012, the company purchased 41.5 million, 41.6 million and 46.6 million common shares for \$5,000, \$5,000 and \$5,000 under its ongoing share repurchase program, respectively.

In 2014, 2013 and 2012, "Net (purchases) sales of other short-term investments" generally consisted of restricted cash associated with upstream abandonment activities, funds held in escrow for tax-deferred exchanges and asset acquisitions, and tax payments that was invested in cash and short-term securities and reclassified from "Cash and cash equivalents" to "Deferred charges and other assets" on the Consolidated Balance Sheet.

The Consolidated Statement of Cash Flows excludes changes to the Consolidated Balance Sheet that did not affect cash. The 2012 period excludes the effects of \$800 of proceeds to be received in future periods for the sale of an equity interest in the Wheatstone Project, of which \$164 has been received as of December 31, 2014. “Capital expenditures” in the 2012 period excludes a \$1,850 increase in “Properties, plant and equipment” related to an upstream asset exchange in Australia. Refer also to Note 24, on page 67, for a discussion of revisions to the company’s AROs that also did not involve cash receipts or payments for the three years ending December 31, 2014.

The major components of “Capital expenditures” and the reconciliation of this amount to the reported capital and exploratory expenditures, including equity affiliates, are presented in the following table:

	Year ended December 31		
	2014	2013	2012
Additions to properties, plant and equipment *	\$ 34,393	\$ 36,550	\$ 29,526
Additions to investments	526	934	1,042
Current-year dry hole expenditures	504	594	475
Payments for other liabilities and assets, net	(16)	(93)	(105)
Capital expenditures	35,407	37,985	30,938
Expensed exploration expenditures	1,110	1,178	1,173
Assets acquired through capital lease obligations and other financing obligations	332	16	1
Capital and exploratory expenditures, excluding equity affiliates	36,849	39,179	32,112
Company’s share of expenditures by equity affiliates	3,467	2,698	2,117
Capital and exploratory expenditures, including equity affiliates	\$ 40,316	\$ 41,877	\$ 34,229

* Excludes noncash additions of \$2,310 in 2014, \$1,661 in 2013 and \$4,569 in 2012.

Note 5

Equity

Retained earnings at December 31, 2014 and 2013, included approximately \$14,512 and \$11,395, respectively, for the company’s share of undistributed earnings of equity affiliates.

At December 31, 2014, about 133 million shares of Chevron’s common stock remained available for issuance from the 260 million shares that were reserved for issuance under the Chevron LTIP. In addition, approximately 174,510 shares remain available for issuance from the 800,000 shares of the company’s common stock that were reserved for awards under the Chevron Corporation Non-Employee Directors’ Equity Compensation and Deferral Plan.

Note 6

Lease Commitments

Certain noncancelable leases are classified as capital leases, and the leased assets are included as part of “Properties, plant and equipment, at cost” on the Consolidated Balance Sheet. Such leasing arrangements involve crude oil production and processing equipment, service stations, bareboat charters, office buildings, and other facilities. Other leases are classified as operating leases and are not capitalized. The payments on operating leases are recorded as expense. Details of the capitalized leased assets are as follows:

	At December 31	
	2014	2013
Upstream	\$ 765	\$ 445
Downstream	97	316
All Other	—	—
Total	862	761
Less: Accumulated amortization	381	523
Net capitalized leased assets	\$ 481	\$ 238

Rental expenses incurred for operating leases during 2014, 2013 and 2012 were as follows:

	Year ended December 31		
	2014	2013	2012
Minimum rentals	\$ 1,080	\$ 1,049	\$ 973
Contingent rentals	1	1	7
Total	1,081	1,050	980
Less: Sublease rental income	14	25	32
Net rental expense	\$ 1,067	\$ 1,025	\$ 948

Contingent rentals are based on factors other than the passage of time, principally sales volumes at leased service stations. Certain leases include escalation clauses for adjusting rentals to reflect changes in price indices, renewal options ranging up to 25 years, and options to purchase the leased property during or at the end of the initial or renewal lease period for the fair market value or other specified amount at that time.

At December 31, 2014, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a noncancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year 2015	\$ 793	\$ 34
2016	644	26
2017	585	21
2018	461	20
2019	326	15
Thereafter	689	24
Total	\$ 3,498	\$ 140
Less: Amounts representing interest and executory costs		\$ (44)
Net present values		96
Less: Capital lease obligations included in short-term debt		(28)
Long-term capital lease obligations		\$ 68

Note 7

Summarized Financial Data – Chevron U.S.A. Inc.

Chevron U.S.A. Inc. (CUSA) is a major subsidiary of Chevron Corporation. CUSA and its subsidiaries manage and operate most of Chevron's U.S. businesses. Assets include those related to the exploration and production of crude oil, natural gas and natural gas liquids and those associated with the refining, marketing, supply and distribution of products derived from petroleum, excluding most of the regulated pipeline operations of Chevron. CUSA also holds the company's investment in the Chevron Phillips Chemical Company LLC joint venture, which is accounted for using the equity method. The summarized financial information for CUSA and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2014	2013	2012
Sales and other operating revenues	\$ 157,198	\$ 174,318	\$ 183,215
Total costs and other deductions	153,139	169,984	175,009
Net income attributable to CUSA	3,849	3,714	6,216

	At December 31	
	2014	2013
Current assets	\$ 13,724	\$ 17,626
Other assets	62,195	57,288
Current liabilities	16,191	17,486
Other liabilities	30,175	28,119
Total CUSA net equity	\$ 29,553	\$ 29,309
Memo: Total debt	\$ 14,473	\$ 14,482

Note 8

Summarized Financial Data – Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 13, beginning on page 48, for a discussion of TCO operations. Summarized financial information for 100 percent of TCO is presented in the table below:

	Year ended December 31		
	2014	2013	2012
Sales and other operating revenues	\$ 22,813	\$ 25,239	\$ 23,089
Costs and other deductions	10,275	11,173	10,064
Net income attributable to TCO	8,772	9,855	9,119

	At December 31	
	2014	2013
Current assets	\$ 3,425	\$ 3,598
Other assets	14,810	12,964
Current liabilities	1,531	3,016
Other liabilities	2,375	2,761
Total TCO net equity	\$ 14,329	\$ 10,785

Note 9

Fair Value Measurements

The three levels of the fair value hierarchy of inputs the company uses to measure the fair value of an asset or a liability are as follows:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities. For the company, Level 1 inputs include exchange-traded futures contracts for which the parties are willing to transact at the exchange-quoted price and marketable securities that are actively traded.

Level 2: Inputs other than Level 1 that are observable, either directly or indirectly. For the company, Level 2 inputs include quoted prices for similar assets or liabilities, prices obtained through third-party broker quotes and prices that can be corroborated with other observable inputs for substantially the complete term of a contract.

Level 3: Unobservable inputs. The company does not use Level 3 inputs for any of its recurring fair value measurements. Level 3 inputs may be required for the determination of fair value associated with certain nonrecurring measurements of nonfinancial assets and liabilities.

The tables on the next page show the fair value hierarchy for assets and liabilities measured at fair value on a recurring and nonrecurring basis at December 31, 2014, and December 31, 2013.

Marketable Securities The company calculates fair value for its marketable securities based on quoted market prices for identical assets. The fair values reflect the cash that would have been received if the instruments were sold at December 31, 2014.

Derivatives The company records its derivative instruments – other than any commodity derivative contracts that are designated as normal purchase and normal sale – on the Consolidated Balance Sheet at fair value, with the offsetting amount to the Consolidated Statement of Income. Derivatives classified as Level 1 include futures, swaps and options contracts traded in active markets such as the New York Mercantile Exchange. Derivatives classified as Level 2 include swaps, options and forward contracts principally with financial institutions and other oil and gas companies, the fair values of which are obtained from third-party broker quotes, industry pricing services and exchanges. The company obtains multiple sources of pricing information for the Level 2 instruments. Since this pricing information is generated from observable market data, it has historically been very consistent. The company does not materially adjust this information.

Properties, Plant and Equipment The company reported impairments for certain oil and gas properties and a mining asset in 2014. The company did not have any material long-lived assets measured at fair value on a nonrecurring basis to report in 2013.

Investments and Advances The company did not have any material investments and advances measured at fair value on a nonrecurring basis to report in 2014 or 2013.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2014					At December 31, 2013				
	Total	Level 1	Level 2	Level 3		Total	Level 1	Level 2	Level 3	
Marketable securities	\$ 422	\$ 422	\$ —	\$ —		\$ 263	\$ 263	\$ —	\$ —	
Derivatives	413	394	19	—		28	—	28	—	
Total Assets at Fair Value	\$ 835	\$ 816	\$ 19	\$ —		\$ 291	\$ 263	\$ 28	\$ —	
Derivatives	84	83	1	—		89	80	9	—	
Total Liabilities at Fair Value	\$ 84	\$ 83	\$ 1	\$ —		\$ 89	\$ 80	\$ 9	\$ —	

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

	At December 31					At December 31				
	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2014	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2013
Properties, plant and equipment, net (held and used)	\$ 947	\$ —	\$ 213	\$ 734	\$ 1,249	\$ 102	\$ —	\$ —	\$ 102	\$ 278
Properties, plant and equipment, net (held for sale)	—	—	—	—	25	69	—	69	—	104
Investments and advances	11	—	—	11	41	38	—	35	3	228
Total Nonrecurring Assets at Fair Value	\$ 958	\$ —	\$ 213	\$ 745	\$ 1,315	\$ 209	\$ —	\$ 104	\$ 105	\$ 610

Assets and Liabilities Not Required to Be Measured at Fair Value The company holds cash equivalents and bank time deposits in U.S. and non-U.S. portfolios. The instruments classified as cash equivalents are primarily bank time deposits with maturities of 90 days or less and money market funds. “Cash and cash equivalents” had carrying/fair values of \$12,785 and \$16,245 at December 31, 2014, and December 31, 2013, respectively. The instruments held in “Time deposits” are bank time deposits with maturities greater than 90 days, and had carrying/fair values of \$8 at both December 31, 2014, and December 31, 2013. The fair values of cash, cash equivalents and bank time deposits are classified as Level 1 and reflect the cash that would have been received if the instruments were settled at December 31, 2014.

“Cash and cash equivalents” do not include investments with a carrying/fair value of \$1,474 and \$1,210 at December 31, 2014, and December 31, 2013, respectively. At December 31, 2014, these investments are classified as Level 1 and include restricted funds related to upstream abandonment activities, funds held in escrow for tax-deferred exchanges and asset acquisitions, and tax payments, which are reported in “Deferred charges and other assets” on the Consolidated Balance Sheet. Long-term debt of \$15,960 and \$11,960 at December 31, 2014, and December 31, 2013, had estimated fair values of \$16,450 and \$12,267, respectively. Long-term debt primarily includes corporate issued bonds. The fair value of corporate bonds is \$15,727 and classified as Level 1. The fair value of the other bonds is \$723 and classified as Level 2.

The carrying values of short-term financial assets and liabilities on the Consolidated Balance Sheet approximate their fair values. Fair value remeasurements of other financial instruments at December 31, 2014 and 2013, were not material.

Note 10**Financial and Derivative Instruments**

Derivative Commodity Instruments Chevron is exposed to market risks related to price volatility of crude oil, refined products, natural gas, natural gas liquids, liquefied natural gas and refinery feedstocks.

The company uses derivative commodity instruments to manage these exposures on a portion of its activity, including firm commitments and anticipated transactions for the purchase, sale and storage of crude oil, refined products, natural gas, natural gas liquids and feedstock for company refineries. From time to time, the company also uses derivative commodity instruments for limited trading purposes.

The company’s derivative commodity instruments principally include crude oil, natural gas and refined product futures, swaps, options, and forward contracts. None of the company’s derivative instruments is designated as a hedging instrument, although certain of the company’s affiliates make such designation. The company’s derivatives are not material to the company’s financial position, results of operations or liquidity. The company believes it has no material market or credit risks to its operations, financial position or liquidity as a result of its commodity derivative activities.

The company uses derivative commodity instruments traded on the New York Mercantile Exchange and on electronic platforms of the Inter-Continental Exchange and Chicago Mercantile Exchange. In addition, the company enters into swap contracts and option contracts principally with major financial institutions and other oil and gas companies in the “over-the-counter” markets, which are governed by International Swaps and Derivatives Association agreements and other master netting arrangements. Depending on the nature of the derivative transactions, bilateral collateral arrangements may also be required.

Derivative instruments measured at fair value at December 31, 2014, December 31, 2013, and December 31, 2012, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are as follows:

Consolidated Balance Sheet: Fair Value of Derivatives Not Designated as Hedging Instruments

Type of Contract	Balance Sheet Classification	At December 31	
		2014	2013
Commodity	Accounts and notes receivable, net	\$ 401	\$ 22
Commodity	Long-term receivables, net	12	6
Total Assets at Fair Value		\$ 413	\$ 28
Commodity	Accounts payable	\$ 57	\$ 65
Commodity	Deferred credits and other noncurrent obligations	27	24
Total Liabilities at Fair Value		\$ 84	\$ 89

Consolidated Statement of Income: The Effect of Derivatives Not Designated as Hedging Instruments

Type of Derivative Contract	Statement of Income Classification	Gain/(Loss)		
		Year ended December 31		
		2014	2013	2012
Commodity	Sales and other operating revenues	\$ 553	\$ (108)	\$ (49)
Commodity	Purchased crude oil and products	(17)	(77)	(24)
Commodity	Other income	(32)	(9)	6
		\$ 504	\$ (194)	\$ (67)

The table below represents gross and net derivative assets and liabilities subject to netting agreements on the Consolidated Balance Sheet at December 31, 2014 and December 31, 2013.

Consolidated Balance Sheet: The Effect of Netting Derivative Assets and Liabilities

At December 31, 2014	Gross Amount Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset	Net Amount
Derivative Assets	\$ 4,004	\$ 3,591	\$ 413	\$ 7	\$ 406
Derivative Liabilities	\$ 3,675	\$ 3,591	\$ 84	\$ —	\$ 84
At December 31, 2013					
Derivative Assets	\$ 732	\$ 704	\$ 28	\$ 27	\$ 1
Derivative Liabilities	\$ 793	\$ 704	\$ 89	\$ —	\$ 89

Derivative assets and liabilities are classified on the Consolidated Balance Sheet as accounts and notes receivable, long-term receivables, accounts payable, and deferred credits and other noncurrent obligations. Amounts not offset on the Consolidated Balance Sheet represent positions that do not meet all the conditions for “a right of offset.”

Concentrations of Credit Risk The company’s financial instruments that are exposed to concentrations of credit risk consist primarily of its cash equivalents, time deposits, marketable securities, derivative financial instruments and trade receivables. The company’s short-term investments are placed with a wide array of financial institutions with high credit ratings. Company investment policies limit the company’s exposure both to credit risk and to concentrations of credit risk. Similar policies on diversification and creditworthiness are applied to the company’s counterparties in derivative instruments.

The trade receivable balances, reflecting the company’s diversified sources of revenue, are dispersed among the company’s broad customer base worldwide. As a result, the company believes concentrations of credit risk are limited. The company routinely assesses the financial strength of its customers. When the financial strength of a customer is not considered sufficient, alternative risk mitigation measures may be deployed, including requiring pre-payments, letters of credit or other acceptable collateral instruments to support sales to customers.

Note 11 Earnings Per Share

Basic earnings per share (EPS) is based upon “Net Income Attributable to Chevron Corporation” (“earnings”) and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company’s stock option programs (refer to Note 21, “Stock Options and Other Share-Based Compensation,” beginning on page 58). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2014	2013	2012
Basic EPS Calculation			
Earnings available to common stockholders - Basic*	\$ 19,241	\$ 21,423	\$ 26,179
Weighted-average number of common shares outstanding	1,883	1,916	1,950
Add: Deferred awards held as stock units	1	1	—
Total weighted-average number of common shares outstanding	1,884	1,917	1,950
Earnings per share of common stock - Basic	\$ 10.21	\$ 11.18	\$ 13.42
Diluted EPS Calculation			
Earnings available to common stockholders - Diluted*	\$ 19,241	\$ 21,423	\$ 26,179
Weighted-average number of common shares outstanding	1,883	1,916	1,950
Add: Deferred awards held as stock units	1	1	—
Add: Dilutive effect of employee stock-based awards	14	15	15
Total weighted-average number of common shares outstanding	1,898	1,932	1,965
Earnings per share of common stock - Diluted	\$ 10.14	\$ 11.09	\$ 13.32

* There was no effect of dividend equivalents paid on stock units or dilutive impact of employee stock-based awards on earnings.

Note 12 Operating Segments and Geographic Data

Although each subsidiary of Chevron is responsible for its own affairs, Chevron Corporation manages its investments in these subsidiaries and their affiliates. The investments are grouped into two business segments, Upstream and Downstream, representing the company’s “reportable segments” and “operating segments.” Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; liquefaction, transportation and regasification associated with liquefied natural gas (LNG); transporting crude oil by major international oil export pipelines; processing, transporting, storage and marketing of natural gas; and a gas-to-liquids plant. Downstream operations consist primarily of refining of crude oil into petroleum products; marketing of crude oil and refined products; transporting of crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant additives. All Other activities of the company include mining activities, power and energy services, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, and technology companies.

The company’s segments are managed by “segment managers” who report to the “chief operating decision maker” (CODM). The segments represent components of the company that engage in activities (a) from which revenues are earned and expenses are incurred; (b) whose operating results are regularly reviewed by the CODM, which makes decisions about resources to be allocated to the segments and assesses their performance; and (c) for which discrete financial information is available.

The company’s primary country of operation is the United States of America, its country of domicile. Other components of the company’s operations are reported as “International” (outside the United States).

Segment Earnings The company evaluates the performance of its operating segments on an after-tax basis, without considering the effects of debt financing interest expense or investment interest income, both of which are managed by the company on a worldwide basis. Corporate administrative costs and assets are not allocated to the operating segments. However, operating segments are billed for the direct use of corporate services. Nonbillable costs remain at the corporate level in “All Other.” Earnings by major operating area are presented in the following table:

	Year ended December 31		
	2014	2013	2012
Segment Earnings			
Upstream			
United States	\$ 3,327	\$ 4,044	\$ 5,332
International	13,566	16,765	18,456
Total Upstream	16,893	20,809	23,788
Downstream			
United States	2,637	787	2,048
International	1,699	1,450	2,251
Total Downstream	4,336	2,237	4,299
Total Segment Earnings	21,229	23,046	28,087
All Other			
Interest income	77	80	83
Other	(2,065)	(1,703)	(1,991)
Net Income Attributable to Chevron Corporation	\$ 19,241	\$ 21,423	\$ 26,179

Segment Assets Segment assets do not include intercompany investments or receivables. Assets at year-end 2014 and 2013 are as follows:

	At December 31	
	2014	2013
Upstream		
United States	\$ 49,205	\$ 45,436
International	152,736	137,096
Goodwill	4,593	4,639
Total Upstream	206,534	187,171
Downstream		
United States	23,068	23,829
International	17,723	20,268
Total Downstream	40,791	44,097
Total Segment Assets	247,325	231,268
All Other		
United States	6,741	7,326
International	11,960	15,159
Total All Other	18,701	22,485
Total Assets – United States	79,014	76,591
Total Assets – International	182,419	172,523
Goodwill	4,593	4,639
Total Assets	\$ 266,026	\$ 253,753

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2014, 2013 and 2012, are presented in the table that follows. Products are transferred between operating segments at internal product values that approximate market prices.

Revenues for the upstream segment are derived primarily from the production and sale of crude oil and natural gas, as well as the sale of third-party production of natural gas. Revenues for the downstream segment are derived from the refining and marketing of petroleum products such as gasoline, jet fuel, gas oils, lubricants, residual fuel oils and other products derived

Notes to the Consolidated Financial Statements

Millions of dollars, except per-share amounts

from crude oil. This segment also generates revenues from the manufacture and sale of fuel and lubricant additives and the transportation and trading of refined products and crude oil. “All Other” activities include revenues from power and energy services, insurance operations, real estate activities and technology companies.

	Year ended December 31		
	2014	2013	2012
Upstream			
United States	\$ 7,455	\$ 8,052	\$ 6,416
Intersegment	15,455	16,865	17,229
Total United States	22,910	24,917	23,645
International	23,808	17,607	19,459
Intersegment	23,107	33,034	34,094
Total International	46,915	50,641	53,553
Total Upstream*	69,825	75,558	77,198
Downstream			
United States	73,942	80,272	83,043
Excise and similar taxes	4,633	4,792	4,665
Intersegment	31	39	49
Total United States	78,606	85,103	87,757
International	86,848	105,373	113,279
Excise and similar taxes	3,553	3,699	3,346
Intersegment	8,839	859	80
Total International	99,240	109,931	116,705
Total Downstream*	177,846	195,034	204,462
All Other			
United States	252	358	378
Intersegment	1,475	1,524	1,300
Total United States	1,727	1,882	1,678
International	3	3	4
Intersegment	28	31	48
Total International	31	34	52
Total All Other	1,758	1,916	1,730
Segment Sales and Other Operating Revenues			
United States	103,243	111,902	113,080
International	146,186	160,606	170,310
Total Segment Sales and Other Operating Revenues	249,429	272,508	283,390
Elimination of intersegment sales	(48,935)	(52,352)	(52,800)
Total Sales and Other Operating Revenues	\$ 200,494	\$ 220,156	\$ 230,590

* Effective January 1, 2014, International Upstream prospectively includes selected amounts previously recognized in International Downstream, which are not material to the company's results of operations or financial position.

Segment Income Taxes Segment income tax expense for the years 2014, 2013 and 2012 is as follows:

	Year ended December 31		
	2014	2013	2012
Upstream			
United States	\$ 2,043	\$ 2,333	\$ 2,820
International	9,217	12,470	16,554
Total Upstream	11,260	14,803	19,374
Downstream			
United States	1,302	364	1,051
International	467	389	587
Total Downstream	1,769	753	1,638
All Other	(1,137)	(1,248)	(1,016)
Total Income Tax Expense	\$ 11,892	\$ 14,308	\$ 19,996

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 13. Information related to properties, plant and equipment by segment is contained in Note 14, on page 49.

Note 13**Investments and Advances**

Equity in earnings, together with investments in and advances to companies accounted for using the equity method and other investments accounted for at or below cost, is shown in the following table. For certain equity affiliates, Chevron pays its share of some income taxes directly. For such affiliates, the equity in earnings does not include these taxes, which are reported on the Consolidated Statement of Income as “Income tax expense.”

	Investments and Advances At December 31		Equity in Earnings Year ended December 31		
	2014	2013	2014	2013	2012
Upstream					
Tengizchevroil	\$ 7,319	\$ 5,875	\$ 4,392	\$ 4,957	\$ 4,614
Petropiar	794	858	26	339	55
Caspian Pipeline Consortium	1,487	1,298	191	113	96
Petroboscan	917	1,375	186	300	229
Angola LNG Limited	3,277	3,423	(311)	(111)	(106)
Other	2,178	2,835	229	214	266
Total Upstream	15,972	15,664	4,713	5,812	5,154
Downstream					
GS Caltex Corporation	2,867	2,518	420	132	249
Chevron Phillips Chemical Company LLC	5,116	4,312	1,606	1,371	1,206
Star Petroleum Refining Company Ltd.	—	—	—	—	22
Caltex Australia Ltd.	1,161	1,020	183	224	77
Other	1,048	989	180	199	196
Total Downstream	10,192	8,839	2,389	1,926	1,750
All Other					
Other	171	375	(4)	(211)	(15)
Total equity method	\$ 26,335	\$ 24,878	\$ 7,098	\$ 7,527	\$ 6,889
Other at or below cost	577	624			
Total investments and advances	\$ 26,912	\$ 25,502			
Total United States	\$ 6,787	\$ 6,638	\$ 1,623	\$ 1,294	\$ 1,268
Total International	\$ 20,125	\$ 18,864	\$ 5,475	\$ 6,233	\$ 5,621

Descriptions of major affiliates, including significant differences between the company’s carrying value of its investments and its underlying equity in the net assets of the affiliates, are as follows:

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), which operates the Tengiz and Korolev crude oil fields in Kazakhstan. At December 31, 2014, the company’s carrying value of its investment in TCO was about \$150 higher than the amount of underlying equity in TCO’s net assets. This difference results from Chevron acquiring a portion of its interest in TCO at a value greater than the underlying book value for that portion of TCO’s net assets. See Note 8, on page 42, for summarized financial information for 100 percent of TCO.

Petropiar Chevron has a 30 percent interest in Petropiar, a joint stock company which operates the Hamaca heavy-oil production and upgrading project in Venezuela’s Orinoco Belt. At December 31, 2014, the company’s carrying value of its investment in Petropiar was approximately \$160 less than the amount of underlying equity in Petropiar’s net assets. The difference represents the excess of Chevron’s underlying equity in Petropiar’s net assets over the net book value of the assets contributed to the venture.

Caspian Pipeline Consortium Chevron has a 15 percent interest in the Caspian Pipeline Consortium, a variable interest entity, which provides the critical export route for crude oil from both TCO and Karachaganak. The company has investments and advances totaling \$1,487, which includes long-term loans of \$1,328 at year-end 2014. The loans were provided to fund 30 percent of the initial pipeline construction. The company is not the primary beneficiary of the consortium because it does not direct activities of the consortium and only receives its proportionate share of the financial returns.

Petroboscan Chevron has a 39.2 percent interest in Petroboscan, a joint stock company which operates the Boscan Field in Venezuela. At December 31, 2014, the company’s carrying value of its investment in Petroboscan was approximately \$160 higher than the amount of underlying equity in Petroboscan’s net assets. The difference reflects the excess of the net book value of the assets contributed by Chevron over its underlying equity in Petroboscan’s net assets.

Angola LNG Limited Chevron has a 36.4 percent interest in Angola LNG Limited, which processes and liquefies natural gas produced in Angola for delivery to international markets.

GS Caltex Corporation Chevron owns 50 percent of GS Caltex Corporation, a joint venture with GS Energy. The joint venture imports, refines and markets petroleum products, petrochemicals and lubricants, predominantly in South Korea.

Chevron Phillips Chemical Company LLC Chevron owns 50 percent of Chevron Phillips Chemical Company LLC. The other half is owned by Phillips 66.

Caltex Australia Ltd. Chevron has a 50 percent equity ownership interest in Caltex Australia Ltd. (CAL). The remaining 50 percent of CAL is publicly owned. At December 31, 2014, the fair value of Chevron's share of CAL common stock was approximately \$3,755.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes \$10,404, \$14,635 and \$17,356 with affiliated companies for 2014, 2013 and 2012, respectively. "Purchased crude oil and products" includes \$6,735, \$7,063 and \$6,634 with affiliated companies for 2014, 2013 and 2012, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes \$924 and \$1,328 due from affiliated companies at December 31, 2014 and 2013, respectively. "Accounts payable" includes \$345 and \$466 due to affiliated companies at December 31, 2014 and 2013, respectively.

The following table provides summarized financial information on a 100 percent basis for all equity affiliates as well as Chevron's total share, which includes Chevron's net loans to affiliates of \$874, \$1,129 and \$1,494 at December 31, 2014, 2013 and 2012, respectively.

Year ended December 31	Affiliates			Chevron Share		
	2014	2013	2012	2014	2013	2012
Total revenues	\$ 123,003	\$ 131,875	\$ 136,065	\$ 58,937	\$ 63,101	\$ 65,196
Income before income tax expense	20,609	24,075	23,016	9,968	11,108	9,856
Net income attributable to affiliates	14,758	15,594	16,786	7,237	7,845	6,938
At December 31						
Current assets	\$ 35,662	\$ 39,713	\$ 37,541	\$ 13,465	\$ 15,156	\$ 14,732
Noncurrent assets	70,817	68,593	66,065	26,053	25,059	23,523
Current liabilities	25,308	29,642	27,878	9,588	11,587	11,093
Noncurrent liabilities	17,983	19,442	19,366	4,211	4,559	4,879
Total affiliates' net equity	\$ 63,188	\$ 59,222	\$ 56,362	\$ 25,719	\$ 24,069	\$ 22,283

Note 14

Properties, Plant and Equipment¹

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost ²			Depreciation Expense ³		
	2014	2013	2012	2014	2013	2012	2014	2013	2012	2014	2013	2012
Upstream												
United States	\$ 96,850	\$ 89,555	\$ 81,908	\$ 45,864	\$ 41,831	\$ 37,909	\$ 9,688	\$ 8,188	\$ 8,211	\$ 5,127	\$ 4,412	\$ 3,902
International	192,637	169,623	145,799	118,926	104,100	85,318	24,920	27,383	21,343	9,688	8,336	8,015
Total Upstream	289,487	259,178	227,707	164,790	145,931	123,227	34,608	35,571	29,554	14,815	12,748	11,917
Downstream												
United States	22,640	22,407	21,792	11,019	11,481	11,333	588	1,154	1,498	886	780	799
International	9,334	9,303	8,990	4,219	4,139	3,930	530	653	2,544	396	360	308
Total Downstream	31,974	31,710	30,782	15,238	15,620	15,263	1,118	1,807	4,042	1,282	1,140	1,107
All Other												
United States	5,673	5,402	4,959	3,077	3,194	2,845	581	721	415	680	286	384
International	155	143	33	68	84	13	25	23	4	16	12	5
Total All Other	5,828	5,545	4,992	3,145	3,278	2,858	606	744	419	696	298	389
Total United States	125,163	117,364	108,659	59,960	56,506	52,087	10,857	10,063	10,124	6,693	5,478	5,085
Total International	202,126	179,069	154,822	123,213	108,323	89,261	25,475	28,059	23,891	10,100	8,708	8,328
Total	\$ 327,289	\$ 296,433	\$ 263,481	\$ 183,173	\$ 164,829	\$ 141,348	\$ 36,332	\$ 38,122	\$ 34,015	\$ 16,793	\$ 14,186	\$ 13,413

¹ Other than the United States, Australia and Nigeria, no other country accounted for 10 percent or more of the company's net properties, plant and equipment (PP&E) in 2014. Australia had \$41,012, \$31,464 and \$21,770 in 2014, 2013, and 2012, respectively. Nigeria had PP&E of \$19,214, \$18,429 and \$17,485 for 2014, 2013 and 2012, respectively.

² Net of dry hole expense related to prior years' expenditures of \$371, \$89 and \$80 in 2014, 2013 and 2012, respectively.

³ Depreciation expense includes accretion expense of \$882, \$627 and \$629 in 2014, 2013 and 2012, respectively.

Note 15

Litigation

MTBE Chevron and many other companies in the petroleum industry have used methyl tertiary butyl ether (MTBE) as a gasoline additive. Chevron is a party to seven pending lawsuits and claims, the majority of which involve numerous other petroleum marketers and refiners. Resolution of these lawsuits and claims may ultimately require the company to correct or ameliorate the alleged effects on the environment of prior release of MTBE by the company or other parties. Additional lawsuits and claims related to the use of MTBE, including personal-injury claims, may be filed in the future. The company's ultimate exposure related to pending lawsuits and claims is not determinable. The company no longer uses MTBE in the manufacture of gasoline in the United States.

Ecuador Chevron is a defendant in a civil lawsuit initiated in the Superior Court of Nueva Loja in Lago Agrio, Ecuador, in May 2003 by plaintiffs who claim to be representatives of certain residents of an area where an oil production consortium formerly had operations. The lawsuit alleges damage to the environment from the oil exploration and production operations and seeks unspecified damages to fund environmental remediation and restoration of the alleged environmental harm, plus a health monitoring program. Until 1992, Texaco Petroleum Company (Texpet), a subsidiary of Texaco Inc., was a minority member of this consortium with Petroecuador, the Ecuadorian state-owned oil company, as the majority partner; since 1990, the operations have been conducted solely by Petroecuador. At the conclusion of the consortium and following an independent third-party environmental audit of the concession area, Texpet entered into a formal agreement with the Republic of Ecuador and Petroecuador for Texpet to remediate specific sites assigned by the government in proportion to Texpet's ownership share of the consortium. Pursuant to that agreement, Texpet conducted a three-year remediation program at a cost of \$40. After certifying that the sites were properly remediated, the government granted Texpet and all related corporate entities a full release from any and all environmental liability arising from the consortium operations.

Based on the history described above, Chevron believes that this lawsuit lacks legal or factual merit. As to matters of law, the company believes first, that the court lacks jurisdiction over Chevron; second, that the law under which plaintiffs bring the action, enacted in 1999, cannot be applied retroactively; third, that the claims are barred by the statute of limitations in Ecuador; and, fourth, that the lawsuit is also barred by the releases from liability previously given to Texpet by the Republic of Ecuador and Petroecuador and by the pertinent provincial and municipal governments. With regard to the facts, the company believes that the evidence confirms that Texpet's remediation was properly conducted and that the remaining environmental damage reflects Petroecuador's failure to timely fulfill its legal obligations and Petroecuador's further conduct since assuming full control over the operations.

In 2008, a mining engineer appointed by the court to identify and determine the cause of environmental damage, and to specify steps needed to remediate it, issued a report recommending that the court assess \$18,900, which would, according to the engineer, provide financial compensation for purported damages, including wrongful death claims, and pay for, among other items, environmental remediation, health care systems and additional infrastructure for Petroecuador. The engineer's report also asserted that an additional \$8,400 could be assessed against Chevron for unjust enrichment. In 2009, following the disclosure by Chevron of evidence that the judge participated in meetings in which businesspeople and individuals holding themselves out as government officials discussed the case and its likely outcome, the judge presiding over the case was recused. In 2010, Chevron moved to strike the mining engineer's report and to dismiss the case based on evidence obtained through discovery in the United States indicating that the report was prepared by consultants for the plaintiffs before being presented as the mining engineer's independent and impartial work and showing further evidence of misconduct. In August 2010, the judge issued an order stating that he was not bound by the mining engineer's report and requiring the parties to provide their positions on damages within 45 days. Chevron subsequently petitioned for recusal of the judge, claiming that he had disregarded evidence of fraud and misconduct and that he had failed to rule on a number of motions within the statutory time requirement.

In September 2010, Chevron submitted its position on damages, asserting that no amount should be assessed against it. The plaintiffs' submission, which relied in part on the mining engineer's report, took the position that damages are between approximately \$16,000 and \$76,000 and that unjust enrichment should be assessed in an amount between approximately \$5,000 and \$38,000. The next day, the judge issued an order closing the evidentiary phase of the case and notifying the parties that he had requested the case file so that he could prepare a judgment. Chevron petitioned to have that order declared a nullity in light of Chevron's prior recusal petition, and because procedural and evidentiary matters remained unresolved. In October 2010, Chevron's motion to recuse the judge was granted. A new judge took charge of the case and revoked the prior judge's order closing the evidentiary phase of the case. On December 17, 2010, the judge issued an order closing the evidentiary phase of the case and notifying the parties that he had requested the case file so that he could prepare a judgment.

On February 14, 2011, the provincial court in Lago Agrio rendered an adverse judgment in the case. The court rejected Chevron's defenses to the extent the court addressed them in its opinion. The judgment assessed approximately \$8,600 in damages and approximately \$900 as an award for the plaintiffs' representatives. It also assessed an additional amount of approximately \$8,600 in punitive damages unless the company issued a public apology within 15 days of the judgment, which Chevron did not do. On February 17, 2011, the plaintiffs appealed the judgment, seeking increased damages, and on March 11, 2011, Chevron appealed the judgment seeking to have the judgment nullified. On January 3, 2012, an appellate panel in the provincial court affirmed the February 14, 2011 decision and ordered that Chevron pay additional attorneys' fees in the amount of "0.10% of the values that are derived from the decisional act of this judgment." The plaintiffs filed a petition to clarify and amplify the appellate decision on January 6, 2012, and the court issued a ruling in response on January 13, 2012, purporting to clarify and amplify its January 3, 2012 ruling, which included clarification that the deadline for the company to issue a public apology to avoid the additional amount of approximately \$8,600 in punitive damages was within 15 days of the clarification ruling, or February 3, 2012. Chevron did not issue an apology because doing so might be mischaracterized as an admission of liability and would be contrary to facts and evidence submitted at trial. On January 20, 2012, Chevron appealed (called a petition for cassation) the appellate panel's decision to Ecuador's National Court of Justice. As part of the appeal, Chevron requested the suspension of any requirement that Chevron post a bond to prevent enforcement under Ecuadorian law of the judgment during the cassation appeal. On February 17, 2012, the appellate panel of the provincial court admitted Chevron's cassation appeal in a procedural step necessary for the National Court of Justice to hear the appeal. The provincial court appellate panel denied Chevron's request for suspension of the requirement that Chevron post a bond and stated that it would not comply with the First and Second Interim Awards of the international arbitration tribunal discussed below. On March 29, 2012, the matter was transferred from the provincial court to the National Court of Justice, and on November 22, 2012, the National Court agreed to hear Chevron's cassation appeal. On August 3, 2012, the provincial court in Lago Agrio approved a court-appointed liquidator's report on damages that calculated the total judgment in the case to be \$19,100. On November 13, 2013, the National Court ratified the judgment but nullified the \$8,600 punitive damage assessment, resulting in a judgment of \$9,500. On December 23, 2013, Chevron appealed the decision to the Ecuador Constitutional Court, Ecuador's highest court, which agreed to consider the appeal on March 20, 2014.

On July 2, 2013, the provincial court in Lago Agrio issued an embargo order in Ecuador ordering that any funds to be paid by the Government of Ecuador to Chevron to satisfy a \$96 award issued in an unrelated action by an arbitral tribunal presiding in the Permanent Court of Arbitration in The Hague under the Rules of the United Nations Commission on International Trade Law must be paid to the Lago Agrio plaintiffs. The award was issued by the tribunal under the United States-Ecuador Bilateral Investment Treaty in an action filed in 2006 in connection with seven breach of contract cases that Texpet filed against the Government of Ecuador between 1991 and 1993. The Government of Ecuador has moved to set aside the tribunal's award. On September 26, 2014, the Supreme Court of the Netherlands issued an opinion denying Ecuador's set aside request. A Federal District Court for the District of Columbia confirmed the tribunal's award, and the Government of Ecuador has appealed the District Court's decision.

Chevron has no assets in Ecuador and the Lago Agrio plaintiffs' lawyers have stated in press releases and through other media that they will seek to enforce the Ecuadorian judgment in various countries and otherwise disrupt Chevron's operations. On May 30, 2012, the Lago Agrio plaintiffs filed an action against Chevron Corporation, Chevron Canada Limited, and Chevron Canada Finance Limited in the Ontario Superior Court of Justice in Ontario, Canada, seeking to recognize and enforce the Ecuadorian judgment. On May 1, 2013, the Ontario Superior Court of Justice held that the Court has jurisdiction over Chevron and Chevron Canada Limited for purposes of the action, but stayed the action due to the absence of evidence that Chevron Corporation has assets in Ontario. The Lago Agrio plaintiffs appealed that decision. On December 17, 2013, the Court of Appeals for Ontario affirmed the lower court's decision on jurisdiction and set aside the stay, allowing the recognition and enforcement action to be heard in the Ontario Superior Court of Justice. Chevron appealed the decision concerning jurisdiction to the Supreme Court of Canada and, on January 16, 2014, the Court of Appeals for Ontario granted Chevron's motion to stay the recognition and enforcement proceeding pending a decision on the admissibility of the Supreme Court appeal. On April 3, 2014, the Supreme Court of Canada granted Chevron's and Chevron Canada Limited's petitions to appeal the Ontario Court of Appeal's decision. On April 8, 2014, Chevron and Chevron Canada Limited filed their notices of appeal with the Canada Supreme Court.

On June 27, 2012, the Lago Agrio plaintiffs filed an action against Chevron Corporation in the Superior Court of Justice in Brasilia, Brazil, seeking to recognize and enforce the Ecuadorian judgment. On October 15, 2012, the provincial court in Lago Agrio issued an ex parte embargo order that purports to order the seizure of assets belonging to separate Chevron subsidiaries in Ecuador, Argentina and Colombia. On November 6, 2012, at the request of the Lago Agrio plaintiffs, a court in Argentina issued a Freeze Order against Chevron Argentina S.R.L. and another Chevron subsidiary, Ingeniero Norberto

Priu, requiring shares of both companies to be “embargoed,” requiring third parties to withhold 40 percent of any payments due to Chevron Argentina S.R.L. and ordering banks to withhold 40 percent of the funds in Chevron Argentina S.R.L. bank accounts. On December 14, 2012, the Argentinean court rejected a motion to revoke the Freeze Order but modified it by ordering that third parties are not required to withhold funds but must report their payments. The court also clarified that the Freeze Order relating to bank accounts excludes taxes. On January 30, 2013, an appellate court upheld the Freeze Order, but on June 4, 2013 the Supreme Court of Argentina revoked the Freeze Order in its entirety. On December 12, 2013, the Lago Agrio plaintiffs served Chevron with notice of their filing of an enforcement proceeding in the National Court, First Instance, of Argentina. Chevron filed its answer on February 27, 2014. Chevron intends to vigorously defend against the proceeding. Chevron continues to believe the provincial court’s judgment is illegitimate and unenforceable in Ecuador, the United States and other countries. The company also believes the judgment is the product of fraud, and contrary to the legitimate scientific evidence. Chevron cannot predict the timing or ultimate outcome of the appeals process in Ecuador or any enforcement action. Chevron expects to continue a vigorous defense of any imposition of liability in the Ecuadorian courts and to contest and defend any and all enforcement actions.

Chevron and Texpet filed an arbitration claim in September 2009 against the Republic of Ecuador before an arbitral tribunal presiding in the Permanent Court of Arbitration in The Hague under the Rules of the United Nations Commission on International Trade Law. The claim alleges violations of the Republic of Ecuador’s obligations under the United States–Ecuador Bilateral Investment Treaty (BIT) and breaches of the settlement and release agreements between the Republic of Ecuador and Texpet (described above), which are investment agreements protected by the BIT. Through the arbitration, Chevron and Texpet are seeking relief against the Republic of Ecuador, including a declaration that any judgment against Chevron in the Lago Agrio litigation constitutes a violation of Ecuador’s obligations under the BIT. On February 9, 2011, the Tribunal issued an Order for Interim Measures requiring the Republic of Ecuador to take all measures at its disposal to suspend or cause to be suspended the enforcement or recognition within and without Ecuador of any judgment against Chevron in the Lago Agrio case pending further order of the Tribunal. On January 25, 2012, the Tribunal converted the Order for Interim Measures into an Interim Award. Chevron filed a renewed application for further interim measures on January 4, 2012, and the Republic of Ecuador opposed Chevron’s application and requested that the existing Order for Interim Measures be vacated on January 9, 2012. On February 16, 2012, the Tribunal issued a Second Interim Award mandating that the Republic of Ecuador take all measures necessary (whether by its judicial, legislative or executive branches) to suspend or cause to be suspended the enforcement and recognition within and without Ecuador of the judgment against Chevron and, in particular, to preclude any certification by the Republic of Ecuador that would cause the judgment to be enforceable against Chevron. On February 27, 2012, the Tribunal issued a Third Interim Award confirming its jurisdiction to hear Chevron’s arbitration claims. On February 7, 2013, the Tribunal issued its Fourth Interim Award in which it declared that the Republic of Ecuador “has violated the First and Second Interim Awards under the [BIT], the UNCITRAL Rules and international law in regard to the finalization and enforcement subject to execution of the Lago Agrio Judgment within and outside Ecuador, including (but not limited to) Canada, Brazil and Argentina.” The Republic of Ecuador filed in the District Court of the Hague a request to set aside the Tribunal’s Interim Awards and the First Partial Award (described below). Chevron filed its answer to the set aside request on December 31, 2014.

The Tribunal has divided the merits phase of the proceeding into three phases. On September 17, 2013, the Tribunal issued its First Partial Award from Phase One, finding that the settlement agreements between the Republic of Ecuador and Texpet applied to Texpet and Chevron, released Texpet and Chevron from claims based on “collective” or “diffuse” rights arising from Texpet’s operations in the former concession area and precluded third parties from asserting collective/diffuse rights environmental claims relating to Texpet’s operations in the former concession area but did not preclude individual claims for personal harm. Chevron awaits a ruling from the Tribunal about whether the claims of the Lago Agrio plaintiffs are individual or collective/diffuse. The Tribunal had set Phase Two to begin on January 20, 2014 to hear Chevron’s denial of justice claims, but on January 2, 2014, the Tribunal postponed Phase Two and held a procedural hearing on January 20-21, 2014. The Tribunal held a hearing on April 29-30, 2014 to address remaining issues relating to Phase One. It also set a hearing on April 20 to May 6, 2015 to address Phase Two issues. The Tribunal has not set a date for Phase Three, which will be the damages phase of the arbitration.

Through a series of U.S. court proceedings initiated by Chevron to obtain discovery relating to the Lago Agrio litigation and the BIT arbitration, Chevron obtained evidence that it believes shows a pattern of fraud, collusion, corruption, and other misconduct on the part of several lawyers, consultants and others acting for the Lago Agrio plaintiffs. In February 2011, Chevron filed a civil lawsuit in the Federal District Court for the Southern District of New York against the Lago Agrio plaintiffs and several of their lawyers, consultants and supporters, alleging violations of the Racketeer Influenced and Corrupt Organizations Act and other state laws. Through the civil lawsuit, Chevron is seeking relief that includes a

declaration that any judgment against Chevron in the Lago Agrio litigation is the result of fraud and other unlawful conduct and is therefore unenforceable. On March 7, 2011, the Federal District Court issued a preliminary injunction prohibiting the Lago Agrio plaintiffs and persons acting in concert with them from taking any action in furtherance of recognition or enforcement of any judgment against Chevron in the Lago Agrio case pending resolution of Chevron's civil lawsuit by the Federal District Court. On May 31, 2011, the Federal District Court severed claims one through eight of Chevron's complaint from the ninth claim for declaratory relief and imposed a discovery stay on claims one through eight pending a trial on the ninth claim for declaratory relief. On September 19, 2011, the U.S. Court of Appeals for the Second Circuit vacated the preliminary injunction, stayed the trial on Chevron's ninth claim, a claim for declaratory relief, that had been set for November 14, 2011, and denied the defendants' mandamus petition to recuse the judge hearing the lawsuit. The Second Circuit issued its opinion on January 26, 2012 ordering the dismissal of Chevron's ninth claim for declaratory relief. On February 16, 2012, the Federal District Court lifted the stay on claims one through eight, and on October 18, 2012, the Federal District Court set a trial date of October 15, 2013. On March 22, 2013, Chevron settled its claims against Stratus Consulting, and on April 12, 2013 sworn declarations by representatives of Stratus Consulting were filed with the Court admitting their role and that of the plaintiffs' attorneys in drafting the environmental report of the mining engineer appointed by the provincial court in Lago Agrio. On September 26, 2013, the Second Circuit denied the defendants' Petition for Writ of Mandamus to recuse the judge hearing the case and to collaterally estop Chevron from seeking a declaration that the Lago Agrio judgment was obtained through fraud and other unlawful conduct. The trial commenced on October 15, 2013 and concluded on November 22, 2013. On March 4, 2014, the Federal District Court entered a judgment in favor of Chevron, prohibiting the defendants from seeking to enforce the Lago Agrio judgment in the United States and further prohibiting them from profiting from their illegal acts. The defendants filed their notices of appeal on March 18, 2014.

The ultimate outcome of the foregoing matters, including any financial effect on Chevron, remains uncertain. Management does not believe an estimate of a reasonably possible loss (or a range of loss) can be made in this case. Due to the defects associated with the Ecuadorian judgment, the 2008 engineer's report on alleged damages and the September 2010 plaintiffs' submission on alleged damages, management does not believe these documents have any utility in calculating a reasonably possible loss (or a range of loss). Moreover, the highly uncertain legal environment surrounding the case provides no basis for management to estimate a reasonably possible loss (or a range of loss).

Note 16

Taxes

Income Taxes

	Year ended December 31		
	2014	2013	2012
Taxes on income			
U.S. federal			
Current	\$ 748	\$ 15	\$ 1,703
Deferred	1,330	1,128	673
State and local			
Current	336	120	652
Deferred	36	74	(145)
Total United States	2,450	1,337	2,883
International			
Current	9,235	12,296	15,626
Deferred	207	675	1,487
Total International	9,442	12,971	17,113
Total taxes on income	\$ 11,892	\$ 14,308	\$ 19,996

In 2014, before-tax income for U.S. operations, including related corporate and other charges, was \$6,296, compared with before-tax income of \$4,672 and \$8,456 in 2013 and 2012, respectively. For international operations, before-tax income was \$24,906, \$31,233 and \$37,876 in 2014, 2013 and 2012, respectively. U.S. federal income tax expense was reduced by \$68, \$175 and \$165 in 2014, 2013 and 2012, respectively, for business tax credits.

The reconciliation between the U.S. statutory federal income tax rate and the company's effective income tax rate is detailed in the following table:

	Year ended December 31		
	2014	2013	2012
U.S. statutory federal income tax rate	35.0 %	35.0 %	35.0 %
Effect of income taxes from international operations at rates different from the U.S. statutory rate	2.8	5.1	7.8
State and local taxes on income, net of U.S. federal income tax benefit	0.7	0.6	0.6
Prior-year tax adjustments	(0.7)	(0.8)	(0.2)
Tax credits	(0.2)	(0.5)	(0.4)
Effects of changes in tax rates	(0.2)	—	0.3
Other	0.7	0.5	0.1
Effective tax rate	38.1 %	39.9 %	43.2 %

The company's effective tax rate decreased from 39.9 percent in 2013 to 38.1 percent in 2014. The decrease primarily resulted from the impact of changes in jurisdictional mix and equity earnings, and the tax effects related to the 2014 sale of interests in Chad and Cameroon, partially offset by other one-time and ongoing tax charges.

The company records its deferred taxes on a tax-jurisdiction basis and classifies those net amounts as current or noncurrent based on the balance sheet classification of the related assets or liabilities. The reported deferred tax balances are composed of the following:

	At December 31	
	2014	2013
Deferred tax liabilities		
Properties, plant and equipment	\$ 28,452	\$ 25,936
Investments and other	3,059	2,272
Total deferred tax liabilities	31,511	28,208
Deferred tax assets		
Foreign tax credits	(11,867)	(11,572)
Abandonment/environmental reserves	(6,686)	(6,279)
Employee benefits	(4,831)	(3,825)
Deferred credits	(1,828)	(2,768)
Tax loss carryforwards	(1,747)	(1,016)
Other accrued liabilities	(498)	(533)
Inventory	(153)	(358)
Miscellaneous	(2,128)	(1,439)
Total deferred tax assets	(29,738)	(27,790)
Deferred tax assets valuation allowance	16,292	17,171
Total deferred taxes, net	\$ 18,065	\$ 17,589

Deferred tax liabilities at the end of 2014 increased by approximately \$3,300 from year-end 2013. The increase was primarily related to increased temporary differences for property, plant and equipment. Deferred tax assets increased by approximately \$1,900 in 2014. Increases primarily related to increased temporary differences for employee benefits.

The overall valuation allowance relates to deferred tax assets for U.S. foreign tax credit carryforwards, tax loss carryforwards and temporary differences. It reduces the deferred tax assets to amounts that are, in management's assessment, more likely than not to be realized. At the end of 2014, the company had tax loss carryforwards of approximately \$5,535 and tax credit carryforwards of approximately \$1,190, primarily related to various international tax jurisdictions. Whereas some of these tax loss carryforwards do not have an expiration date, others expire at various times from 2015 through 2029. U.S. foreign tax credit carryforwards of \$11,867 will expire between 2015 and 2024.

At December 31, 2014 and 2013, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2014	2013
Prepaid expenses and other current assets	\$ (1,071)	\$ (1,341)
Deferred charges and other assets	(3,597)	(2,954)
Federal and other taxes on income	813	583
Noncurrent deferred income taxes	21,920	21,301
Total deferred income taxes, net	\$ 18,065	\$ 17,589

Income taxes are not accrued for unremitted earnings of international operations that have been or are intended to be reinvested indefinitely. Undistributed earnings of international consolidated subsidiaries and affiliates for which no deferred income tax provision has been made for possible future remittances totaled approximately \$35,700 at December 31, 2014. This amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of taxes that might be payable on the possible remittance of earnings that are intended to be reinvested indefinitely. At the end of 2014, deferred income taxes were recorded for the undistributed earnings of certain international operations where indefinite reinvestment of the earnings is not planned. The company does not anticipate incurring significant additional taxes on remittances of earnings that are not indefinitely reinvested.

Uncertain Income Tax Positions The company recognizes a tax benefit in the financial statements for an uncertain tax position only if management's assessment is that the position is "more likely than not" (i.e., a likelihood greater than 50 percent) to be allowed by the tax jurisdiction based solely on the technical merits of the position. The term "tax position" in the accounting standards for income taxes refers to a position in a previously filed tax return or a position expected to be taken in a future tax return that is reflected in measuring current or deferred income tax assets and liabilities for interim or annual periods.

The following table indicates the changes to the company's unrecognized tax benefits for the years ended December 31, 2014, 2013 and 2012. The term "unrecognized tax benefits" in the accounting standards for income taxes refers to the differences between a tax position taken or expected to be taken in a tax return and the benefit measured and recognized in the financial statements. Interest and penalties are not included.

	2014	2013	2012
Balance at January 1	\$ 3,848	\$ 3,071	\$ 3,481
Foreign currency effects	(25)	(58)	4
Additions based on tax positions taken in current year	354	276	543
Additions/reductions resulting from current-year asset acquisitions/sales	(22)	—	—
Additions for tax positions taken in prior years	37	1,164	152
Reductions for tax positions taken in prior years	(561)	(176)	(899)
Settlements with taxing authorities in current year	(50)	(320)	(138)
Reductions as a result of a lapse of the applicable statute of limitations	(29)	(109)	(72)
Balance at December 31	\$ 3,552	\$ 3,848	\$ 3,071

The decrease in unrecognized tax benefits between December 31, 2013, and December 31, 2014 was primarily due to the expiration of certain U.S. foreign tax credits in 2014, which had no impact on the company's results of operations.

Approximately 68 percent of the \$3,552 of unrecognized tax benefits at December 31, 2014, would have an impact on the effective tax rate if subsequently recognized. Certain of these unrecognized tax benefits relate to tax carryforwards that may require a full valuation allowance at the time of any such recognition.

Tax positions for Chevron and its subsidiaries and affiliates are subject to income tax audits by many tax jurisdictions throughout the world. For the company's major tax jurisdictions, examinations of tax returns for certain prior tax years had not been completed as of December 31, 2014. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States – 2008, Nigeria – 2000, Angola – 2001, Saudi Arabia – 2012 and Kazakhstan – 2007.

The company engages in ongoing discussions with tax authorities regarding the resolution of tax matters in the various jurisdictions. Both the outcome of these tax matters and the timing of resolution and/or closure of the tax audits are highly uncertain. However, it is reasonably possible that developments on tax matters in certain tax jurisdictions may result in significant increases or decreases in the company's total unrecognized tax benefits within the next 12 months. Given the number of years that still remain subject to examination and the number of matters being examined in the various tax jurisdictions, the company is unable to estimate the range of possible adjustments to the balance of unrecognized tax benefits.

On the Consolidated Statement of Income, the company reports interest and penalties related to liabilities for uncertain tax positions as "Income tax expense." As of December 31, 2014, accruals of \$233 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of \$215 as of year-end 2013. Income tax expense (benefit) associated with interest and penalties was \$4, \$(42) and \$145 in 2014, 2013 and 2012, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2014	2013	2012
United States			
Excise and similar taxes on products and merchandise	\$ 4,633	\$ 4,792	\$ 4,665
Import duties and other levies	6	4	1
Property and other miscellaneous taxes	1,002	1,036	782
Payroll taxes	273	255	240
Taxes on production	349	333	328
Total United States	6,263	6,420	6,016
International			
Excise and similar taxes on products and merchandise	3,553	3,700	3,345
Import duties and other levies	45	41	106
Property and other miscellaneous taxes	2,277	2,486	2,501
Payroll taxes	172	168	160
Taxes on production	230	248	248
Total International	6,277	6,643	6,360
Total taxes other than on income	\$ 12,540	\$ 13,063	\$ 12,376

Note 17**Long-Term Debt**

Total long-term debt, excluding capital leases, at December 31, 2014, was \$23,960. The company's long-term debt outstanding at year-end 2014 and 2013 was as follows:

	At December 31	
	2014	2013
3.191% notes due 2023	\$ 2,250	\$ 2,250
1.104% notes due 2017	2,000	2,000
1.718% notes due 2018	2,000	2,000
2.355% notes due 2022	2,000	2,000
4.95% notes due 2019	1,500	1,500
1.345% notes due 2017	1,100	—
2.427% notes due 2020	1,000	1,000
2.193% notes due 2019	750	—
0.889% notes due 2016	750	750
Floating rate notes due 2016 (0.332%) ¹	700	—
Floating rate notes due 2017 (0.402%) ¹	650	—
Floating rate notes due 2019 (0.642%) ¹	400	—
Floating rate notes due 2021 (0.762%) ¹	400	—
8.625% debentures due 2032	147	147
8.625% debentures due 2031	107	107
8.0% debentures due 2032	74	74
9.75% debentures due 2020	54	54
8.875% debentures due 2021	40	40
Medium-term notes, maturing from 2021 to 2038 (5.83%) ²	38	38
Total including debt due within one year	15,960	11,960
Debt due within one year	—	—
Reclassified from short-term debt	8,000	8,000
Total long-term debt	\$ 23,960	\$ 19,960

¹ Interest rate at December 31, 2014.

² Weighted-average interest rate at December 31, 2014.

Chevron has an automatic shelf registration statement that expires in 2015. This registration statement is for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

Long-term debt of \$15,960 matures as follows: 2015 – \$0; 2016 – \$1,450; 2017 – \$3,750; 2018 – \$2,000; 2019 – \$2,650; and after 2019 – \$6,110.

In November 2014, \$4,000 of Chevron Corporation bonds were issued.

See Note 9, beginning on page 42, for information concerning the fair value of the company's long-term debt.

Note 18**Short-Term Debt**

	At December 31	
	2014	2013
Commercial paper*	\$ 8,506	\$ 5,130
Notes payable to banks and others with originating terms of one year or less	104	49
Current maturities of long-term debt	—	—
Current maturities of long-term capital leases	22	34
Redeemable long-term obligations		
Long-term debt	3,152	3,152
Capital leases	6	9
Subtotal	11,790	8,374
Reclassified to long-term debt	(8,000)	(8,000)
Total short-term debt	\$ 3,790	\$ 374

* Weighted-average interest rates at December 31, 2014 and 2013, were 0.12 percent and 0.09 percent, respectively.

Redeemable long-term obligations consist primarily of tax-exempt variable-rate put bonds that are included as current liabilities because they become redeemable at the option of the bondholders during the year following the balance sheet date.

The company may periodically enter into interest rate swaps on a portion of its short-term debt. At December 31, 2014, the company had no interest rate swaps on short-term debt.

At December 31, 2014, the company had \$8,000 in committed credit facilities with various major banks, expiring in December 2016, that enable the refinancing of short-term obligations on a long-term basis. These facilities support commercial paper borrowing and can also be used for general corporate purposes. The company's practice has been to continually replace expiring commitments with new commitments on substantially the same terms, maintaining levels management believes appropriate. Any borrowings under the facilities would be unsecured indebtedness at interest rates based on the London Interbank Offered Rate or an average of base lending rates published by specified banks and on terms reflecting the company's strong credit rating. No borrowings were outstanding under these facilities at December 31, 2014.

At both December 31, 2014 and 2013, the company classified \$8,000 of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital within one year, and the company has both the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

Note 19**New Accounting Standards**

Revenue Recognition (Topic 606), Revenue from Contracts with Customers (ASU 2014-09) In May 2014, the FASB issued ASU 2014-09, which becomes effective for the company January 1, 2017. Early adoption is not permitted. The standard provides that an entity should recognize revenue to align with the transfer of promised goods or services to customers in an amount that reflects the consideration that the entity expects to be entitled to receive in exchange for those goods or services. The ASU, which replaces most existing revenue recognition guidance in U.S. GAAP, provides a five-step model for recognition of revenue, guidance on the accounting for certain costs of obtaining or fulfilling contracts with customers and specific disclosure requirements. Transition guidance permits either retrospective application or presentation of the cumulative effect at the adoption date. The company is reviewing the requirements of the ASU to determine the transition method it will apply and to update its assessments developed throughout the FASB's deliberation period. The company is evaluating the effect of the standard on the company's consolidated financial statements.

Note 20**Accounting for Suspended Exploratory Wells**

The company continues to capitalize exploratory well costs after the completion of drilling when (a) the well has found a sufficient quantity of reserves to justify completion as a producing well, and (b) the business unit is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if the company obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well would be assumed to be impaired, and its costs, net of any salvage value, would be charged to expense.

The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2014:

	2014	2013	2012
Beginning balance at January 1	\$ 3,245	\$ 2,681	\$ 2,434
Additions to capitalized exploratory well costs pending the determination of proved reserves	1,591	885	595
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(298)	(290)	(244)
Capitalized exploratory well costs charged to expense	(312)	(31)	(49)
Other reductions*	(31)	—	(55)
Ending balance at December 31	\$ 4,195	\$ 3,245	\$ 2,681

* Represents property sales.

The following table provides an aging of capitalized well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling.

	At December 31		
	2014	2013	2012
Exploratory well costs capitalized for a period of one year or less	\$ 1,522	\$ 641	\$ 501
Exploratory well costs capitalized for a period greater than one year	2,673	2,604	2,180
Balance at December 31	\$ 4,195	\$ 3,245	\$ 2,681
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	51	51	46

* Certain projects have multiple wells or fields or both.

Of the \$2,673 of exploratory well costs capitalized for more than one year at December 31, 2014, \$1,460 (21 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The \$1,213 balance is related to 30 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not under way or firmly planned for the near future. Additional drilling was not deemed necessary because the presence of hydrocarbons had already been established, and other activities were in process to enable a future decision on project development.

The projects for the \$1,213 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) \$289 (six projects) – undergoing front-end engineering and design with final investment decision expected within two years; (b) \$213 (three projects) – development concept under review by government; (c) \$600 (10 projects) – development alternatives under review; (d) \$111 (11 projects) – miscellaneous activities for projects with smaller amounts suspended. While progress was being made on all 51 projects, the decision on the recognition of proved reserves under SEC rules in some cases may not occur for several years because of the complexity, scale and negotiations associated with the projects. Approximately half of these decisions are expected to occur in the next five years.

The \$2,673 of suspended well costs capitalized for a period greater than one year as of December 31, 2014, represents 209 exploratory wells in 51 projects. The tables below contain the aging of these costs on a well and project basis:

<i>Aging based on drilling completion date of individual wells:</i>	Amount	Number of wells
1997–2003	\$ 204	38
2004–2008	459	45
2009–2013	2,010	126
Total	\$ 2,673	209

<i>Aging based on drilling completion date of last suspended well in project:</i>	Amount	Number of projects
1999	\$ 8	1
2003–2009	521	11
2010–2014	2,144	39
Total	\$ 2,673	51

Note 21

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2014, 2013 and 2012 was \$287 (\$186 after tax), \$292 (\$190 after tax) and \$283 (\$184 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance units and restricted stock units was \$71 (\$46 after tax), \$223 (\$145 after tax) and \$177 (\$115 after tax) for 2014, 2013 and 2012, respectively. No significant stock-based compensation cost was capitalized at December 31, 2014, or December 31, 2013.

Cash received in payment for option exercises under all share-based payment arrangements for 2014, 2013 and 2012 was \$527, \$553 and \$753, respectively. Actual tax benefits realized for the tax deductions from option exercises were \$54, \$73 and \$101 for 2014, 2013 and 2012, respectively.

Cash paid to settle performance units and stock appreciation rights was \$204, \$186 and \$123 for 2014, 2013 and 2012, respectively.

Chevron Long-Term Incentive Plan (LTIP) Awards under the LTIP may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance units and nonstock grants. From April 2004 through May 2023, no more than 260 million shares may be issued under the LTIP. For awards issued on or after May 29, 2013, no more than 50 million of those shares may be in a form other than a stock option, stock appreciation right or award requiring full payment for shares by the award recipient. For the major types of awards outstanding as of December 31, 2014, the contractual terms vary between three years for the performance units and 10 years for the stock options and stock appreciation rights.

Unocal Share-Based Plans (Unocal Plans) When Chevron acquired Unocal in August 2005, outstanding stock options and stock appreciation rights granted under various Unocal Plans were exchanged for fully vested Chevron options and appreciation rights. These awards retained the same provisions as the original Unocal Plans. Unexercised awards began expiring in early 2010 and will continue to expire through early 2015.

The fair market values of stock options and stock appreciation rights granted in 2014, 2013 and 2012 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2014	2013	2012
Expected term in years ¹	6.0	6.0	6.0
Volatility ²	30.3 %	31.3 %	31.7 %
Risk-free interest rate based on zero coupon U.S. treasury note	1.9 %	1.2 %	1.1 %
Dividend yield	3.3 %	3.3 %	3.2 %
Weighted-average fair value per option granted	\$ 25.86	\$ 24.48	\$ 23.35

¹ Expected term is based on historical exercise and postvesting cancellation data.

² Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.

A summary of option activity during 2014 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Averaged Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at January 1, 2014	75,626	\$ 88.44		
Granted	11,380	\$ 116.00		
Exercised	(7,464)	\$ 72.71		
Forfeited	(1,201)	\$ 111.73		
Outstanding at December 31, 2014	78,341	\$ 93.59	5.84	\$ 1,548
Exercisable at December 31, 2014	56,943	\$ 85.60	4.87	\$ 1,533

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2014, 2013 and 2012 was \$398, \$445 and \$580, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2014, there was \$226 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted under the plans. That cost is expected to be recognized over a weighted-average period of 1.7 years.

At January 1, 2014, the number of LTIP performance units outstanding was equivalent to 2,531,270 shares. During 2014, 772,800 units were granted, 967,234 units vested with cash proceeds distributed to recipients and 70,884 units were forfeited. At December 31, 2014, units outstanding were 2,265,952. The fair value of the liability recorded for these instruments was \$212, and was measured using the Monte Carlo simulation method. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP and former Unocal programs totaled approximately 3.3 million equivalent shares as of December 31, 2014. A liability of \$78 was recorded for these awards.

Note 22**Employee Benefit Plans**

The company has defined benefit pension plans for many employees. The company typically prefunds defined benefit plans as required by local regulations or in certain situations where prefunding provides economic advantages. In the United States, all qualified plans are subject to the Employee Retirement Income Security Act (ERISA) minimum funding standard. The company does not typically fund U.S. nonqualified pension plans that are not subject to funding requirements under laws and regulations because contributions to these pension plans may be less economic and investment returns may be less attractive than the company's other investment alternatives.

The company also sponsors other postretirement (OPEB) plans that provide medical and dental benefits, as well as life insurance for some active and qualifying retired employees. The plans are unfunded, and the company and retirees share the costs. Medical coverage for Medicare-eligible retirees in the company's main U.S. medical plan is secondary to Medicare (including Part D) and the increase to the company contribution for retiree medical coverage is limited to no more than 4 percent each year. Certain life insurance benefits are paid by the company.

The company recognizes the overfunded or underfunded status of each of its defined benefit pension and OPEB plans as an asset or liability on the Consolidated Balance Sheet.

The funded status of the company's pension and other postretirement benefit plans for 2014 and 2013 follows:

	Pension Benefits				Other Benefits	
	2014		2013		2014	2013
	U.S.	Int'l.	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	\$ 12,080	\$ 6,095	\$ 13,654	\$ 6,287	\$ 3,138	\$ 3,787
Service cost	450	190	495	197	50	66
Interest cost	494	340	471	314	148	149
Plan participants' contributions	—	8	—	8	150	154
Plan amendments	—	3	(78)	18	2	—
Actuarial (gain) loss	2,299	336	(1,398)	(206)	544	(636)
Foreign currency exchange rate changes	—	(348)	—	(187)	(22)	(23)
Benefits paid	(1,073)	(293)	(1,064)	(336)	(350)	(359)
Divestitures	—	(564)	—	—	—	—
Benefit obligation at December 31	14,250	5,767	12,080	6,095	3,660	3,138
Change in Plan Assets						
Fair value of plan assets at January 1	11,210	4,543	9,909	4,125	—	—
Actual return on plan assets	854	571	1,546	375	—	—
Foreign currency exchange rate changes	—	(279)	—	(21)	—	—
Employer contributions	99	276	819	392	200	205
Plan participants' contributions	—	8	—	8	150	154
Benefits paid	(1,073)	(293)	(1,064)	(336)	(350)	(359)
Divestitures	—	(582)	—	—	—	—
Fair value of plan assets at December 31	11,090	4,244	11,210	4,543	—	—
Funded Status at December 31	\$ (3,160)	\$ (1,523)	\$ (870)	\$ (1,552)	\$ (3,660)	\$ (3,138)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and other postretirement benefit plans at December 31, 2014 and 2013, include:

	Pension Benefits				Other Benefits	
	2014		2013		2014	2013
	U.S.	Int'l.	U.S.	Int'l.		
Deferred charges and other assets	\$ 13	\$ 244	\$ 394	\$ 128	\$ —	\$ —
Accrued liabilities	(123)	(68)	(76)	(81)	(198)	(215)
Noncurrent employee benefit plans	(3,050)	(1,699)	(1,188)	(1,599)	(3,462)	(2,923)
Net amount recognized at December 31	\$ (3,160)	\$ (1,523)	\$ (870)	\$ (1,552)	\$ (3,660)	\$ (3,138)

Amounts recognized on a before-tax basis in “Accumulated other comprehensive loss” for the company’s pension and OPEB plans were \$7,417 and \$5,464 at the end of 2014 and 2013, respectively. These amounts consisted of:

	Pension Benefits						Other Benefits	
	2014		2013		2014	2013		
	U.S.	Int'l.	U.S.	Int'l.				
Net actuarial loss	\$ 4,972	\$ 1,487	\$ 3,185	\$ 1,808	\$ 763	\$ 256		
Prior service (credit) costs	(13)	150	(22)	167	58	70		
Total recognized at December 31	\$ 4,959	\$ 1,637	\$ 3,163	\$ 1,975	\$ 821	\$ 326		

The accumulated benefit obligations for all U.S. and international pension plans were \$12,833 and \$4,995, respectively, at December 31, 2014, and \$10,876 and \$5,108, respectively, at December 31, 2013.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2014 and 2013, was:

	Pension Benefits			
	2014		2013	
	U.S.	Int'l.	U.S.	Int'l.
Projected benefit obligations	\$ 14,182	\$ 1,938	\$ 1,267	\$ 1,692
Accumulated benefit obligations	12,765	1,525	1,155	1,240
Fair value of plan assets	11,009	262	4	203

The components of net periodic benefit cost and amounts recognized in the Consolidated Statement of Comprehensive Income for 2014, 2013 and 2012 are shown in the table below:

	Pension Benefits						Other Benefits		
	2014		2013		2012		2014	2013	2012
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Net Periodic Benefit Cost									
Service cost	\$ 450	\$ 190	\$ 495	\$ 197	\$ 452	\$ 181	\$ 50	\$ 66	\$ 61
Interest cost	494	340	471	314	435	320	148	149	153
Expected return on plan assets	(788)	(298)	(701)	(274)	(634)	(269)	—	—	—
Amortization of prior service costs (credits)	(9)	21	2	21	(7)	18	14	(50)	(72)
Recognized actuarial losses	209	96	485	143	470	136	7	53	56
Settlement losses	237	208	173	12	220	5	—	—	(26)
Curtailment losses (gains)	—	—	—	—	—	—	—	—	—
Total net periodic benefit cost	593	557	925	413	936	391	219	218	172
Changes Recognized in Comprehensive Income									
Net actuarial (gain) loss during period	2,233	(17)	(2,244)	(476)	805	330	514	(659)	45
Amortization of actuarial loss	(446)	(304)	(658)	(155)	(700)	(141)	(7)	(53)	(79)
Prior service (credits) costs during period	—	4	(78)	18	94	37	2	—	11
Amortization of prior service (costs) credits	9	(21)	(2)	(21)	7	(18)	(14)	50	72
Total changes recognized in other comprehensive income	1,796	(338)	(2,982)	(634)	206	208	495	(662)	49
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	\$ 2,389	\$ 219	\$(2,057)	\$ (221)	\$ 1,142	\$ 599	\$ 714	\$ (444)	\$ 221

Net actuarial losses recorded in “Accumulated other comprehensive loss” at December 31, 2014, for the company’s U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 10, 12 and 15 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2015, the company estimates actuarial losses of \$356, \$81 and \$34 will be amortized from “Accumulated other comprehensive loss” for U.S. pension, international pension and OPEB plans, respectively. In addition, the company estimates an additional \$216 will be recognized from “Accumulated other comprehensive loss” during 2015 related to lump-sum settlement costs from U.S. pension plans.

The weighted average amortization period for recognizing prior service costs (credits) recorded in “Accumulated other comprehensive loss” at December 31, 2014, was approximately 5 and 9 years for U.S. and international pension plans, respectively, and 7 years for other postretirement benefit plans. During 2015, the company estimates prior service (credits) costs of \$(9), \$22 and \$14 will be amortized from “Accumulated other comprehensive loss” for U.S. pension, international pension and OPEB plans, respectively.

Assumptions The following weighted-average assumptions were used to determine benefit obligations and net periodic benefit costs for years ended December 31:

	Pension Benefits						Other Benefits		
	2014		2013		2012		2014	2013	2012
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Assumptions used to determine benefit obligations:									
Discount rate	3.7%	5.0%	4.3%	5.8%	3.6%	5.2%	4.3%	4.9%	4.1%
Rate of compensation increase	4.5%	5.1%	4.5%	5.5%	4.5%	5.5%	N/A	N/A	N/A
Assumptions used to determine net periodic benefit cost:									
Discount rate	4.3%	5.8%	3.6%	5.2%	3.8%	5.9%	4.9%	4.1%	4.2%
Expected return on plan assets	7.5%	6.6%	7.5%	6.8%	7.5%	7.5%	N/A	N/A	N/A
Rate of compensation increase	4.5%	5.5%	4.5%	5.5%	4.5%	5.7%	N/A	N/A	N/A

Expected Return on Plan Assets The company’s estimated long-term rates of return on pension assets are driven primarily by actual historical asset-class returns, an assessment of expected future performance, advice from external actuarial firms and the incorporation of specific asset-class risk factors. Asset allocations are periodically updated using pension plan asset/liability studies, and the company’s estimated long-term rates of return are consistent with these studies.

For 2014, the company used an expected long-term rate of return of 7.5 percent for U.S. pension plan assets, which account for 72 percent of the company’s pension plan assets. In both 2013 and 2012, the company used a long-term rate of return of 7.5 for this plan.

The market-related value of assets of the major U.S. pension plan used in the determination of pension expense was based on the market values in the three months preceding the year-end measurement date. Management considers the three-month time period long enough to minimize the effects of distortions from day-to-day market volatility and still be contemporaneous to the end of the year. For other plans, market value of assets as of year-end is used in calculating the pension expense.

Discount Rate The discount rate assumptions used to determine the U.S. and international pension and postretirement benefit plan obligations and expense reflect the rate at which benefits could be effectively settled, and is equal to the equivalent single rate resulting from yield curve analysis. This analysis considered the projected benefit payments specific to the company’s plans and the yields on high-quality bonds. At December 31, 2014, the company used a 3.7 percent discount rate for the U.S. pension plans and 4.1 percent for the main U.S. OPEB plan. The discount rates for these plans at the end of 2013 were 4.3 and 4.7 percent, respectively, while in 2012 they were 3.6 and 3.9 percent for these plans, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2014, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 7.0 percent in 2015 and gradually decline to 4.5 percent for 2025 and beyond. For this measurement at December 31, 2013, the assumed health care cost-trend rates started with 7.3 percent in 2014 and gradually declined to 4.5 percent for 2025 and beyond. In both measurements, the annual increase to company contributions was capped at 4 percent.

Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. The impact is mitigated by the 4 percent cap on the company’s medical contributions for the primary U.S. plan. A 1-percentage-point change in the assumed health care cost-trend rates would have the following effects on worldwide plans:

	1 Percent Increase		1 Percent Decrease	
Effect on total service and interest cost components	\$	13	\$	(10)
Effect on postretirement benefit obligation	\$	226	\$	(187)

Plan Assets and Investment Strategy The fair value hierarchy of inputs the company uses to value the pension assets is divided into three levels:

Level 1: Fair values of these assets are measured using unadjusted quoted prices for the assets or the prices of identical assets in active markets that the plans have the ability to access.

Level 2: Fair values of these assets are measured based on quoted prices for similar assets in active markets; quoted prices for identical or similar assets in inactive markets; inputs other than quoted prices that are observable for the asset; and inputs that are derived principally from, or corroborated by, observable market data through correlation or other means. If the asset has a contractual term, the Level 2 input is observable for substantially the full term of the asset. The fair values for Level 2 assets are generally obtained from third-party broker quotes, independent pricing services and exchanges.

Level 3: Inputs to the fair value measurement are unobservable for these assets. Valuation may be performed using a financial model incorporating estimated inputs.

The fair value measurements of the company's pension plans for 2014 and 2013 are below:

	U.S.				Int'l.			
	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
At December 31, 2013								
Equities								
U.S. ¹	\$ 2,298	\$ 2,298	\$ —	\$ —	\$ 409	\$ 409	\$ —	\$ —
International	1,501	1,501	—	—	533	533	—	—
Collective Trusts/Mutual Funds ²	2,977	26	2,951	—	1,066	211	855	—
Fixed Income								
Government	81	52	29	—	726	46	680	—
Corporate	1,275	—	1,275	—	545	23	499	23
Mortgage-Backed Securities	1	—	1	—	4	—	2	2
Other Asset Backed	—	—	—	—	—	—	—	—
Collective Trusts/Mutual Funds ²	1,357	—	1,357	—	647	27	620	—
Mixed Funds ³	—	—	—	—	120	5	115	—
Real Estate ⁴	1,265	—	—	1,265	294	—	—	294
Cash and Cash Equivalents	385	385	—	—	173	173	—	—
Other ⁵	70	(2)	18	54	26	(2)	25	3
Total at December 31, 2013	\$ 11,210	\$ 4,260	\$ 5,631	\$ 1,319	\$ 4,543	\$ 1,425	\$ 2,796	\$ 322
At December 31, 2014								
Equities								
U.S. ¹	\$ 2,087	\$ 2,087	\$ —	\$ —	\$ 241	\$ 241	\$ —	\$ —
International	1,297	1,297	—	—	313	313	—	—
Collective Trusts/Mutual Funds ²	3,240	22	3,218	—	979	173	806	—
Fixed Income								
Government	84	47	37	—	1,066	53	1,013	—
Corporate	1,502	—	1,502	—	585	26	537	22
Mortgage-Backed Securities	1	—	1	—	1	—	1	—
Other Asset Backed	—	—	—	—	—	—	—	—
Collective Trusts/Mutual Funds ²	1,174	—	1,174	—	394	16	378	—
Mixed Funds ³	—	—	—	—	122	3	119	—
Real Estate ⁴	1,364	—	—	1,364	329	—	—	329
Cash and Cash Equivalents	270	270	—	—	190	189	1	—
Other ⁵	71	(3)	20	54	24	—	21	3
Total at December 31, 2014	\$ 11,090	\$ 3,720	\$ 5,952	\$ 1,418	\$ 4,244	\$ 1,014	\$ 2,876	\$ 354

¹ U.S. equities include investments in the company's common stock in the amount of \$24 at December 31, 2014, and \$28 at December 31, 2013.

² Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly index funds. For these index funds, the Level 2 designation is partially based on the restriction that advance notification of redemptions, typically two business days, is required.

³ Mixed funds are composed of funds that invest in both equity and fixed-income instruments in order to diversify and lower risk.

⁴ The year-end valuations of the U.S. real estate assets are based on internal appraisals by the real estate managers, which are updates of third-party appraisals that occur at least once a year for each property in the portfolio.

⁵ The "Other" asset class includes net payables for securities purchased but not yet settled (Level 1); dividends and interest- and tax-related receivables (Level 2); insurance contracts and investments in private-equity limited partnerships (Level 3).

The effects of fair value measurements using significant unobservable inputs on changes in Level 3 plan assets are outlined below:

	Fixed Income					Total
	Corporate	Mortgage-Backed Securities	Real Estate	Other		
Total at December 31, 2012	\$ 31	\$ 2	\$ 1,290	\$ 57	\$	1,380
Actual Return on Plan Assets:						
Assets held at the reporting date	(9)	—	90	—		81
Assets sold during the period	—	—	3	—		3
Purchases, Sales and Settlements	1	—	176	—		177
Transfers in and/or out of Level 3	—	—	—	—		—
Total at December 31, 2013	\$ 23	\$ 2	\$ 1,559	\$ 57	\$	1,641
Actual Return on Plan Assets:						
Assets held at the reporting date	—	—	115	—		115
Assets sold during the period	—	—	20	—		20
Purchases, Sales and Settlements	(1)	(2)	(1)	—		(4)
Transfers in and/or out of Level 3	—	—	—	—		—
Total at December 31, 2014	\$ 22	\$ —	\$ 1,693	\$ 57	\$	1,772

The primary investment objectives of the pension plans are to achieve the highest rate of total return within prudent levels of risk and liquidity, to diversify and mitigate potential downside risk associated with the investments, and to provide adequate liquidity for benefit payments and portfolio management.

The company's U.S. and U.K. pension plans comprise 91 percent of the total pension assets. Both the U.S. and U.K. plans have an Investment Committee that regularly meets during the year to review the asset holdings and their returns. To assess the plans' investment performance, long-term asset allocation policy benchmarks have been established.

For the primary U.S. pension plan, the company's Benefit Plan Investment Committee has established the following approved asset allocation ranges: Equities 40–70 percent, Fixed Income and Cash 20–60 percent, Real Estate 0–15 percent, and Other 0–5 percent. For the U.K. pension plan, the U.K. Board of Trustees has established the following asset allocation guidelines, which are reviewed regularly: Equities 30–50 percent, Fixed Income and Cash 35–65 percent and Real Estate 5–15 percent. The other significant international pension plans also have established maximum and minimum asset allocation ranges that vary by plan. Actual asset allocation within approved ranges is based on a variety of current economic and market conditions and consideration of specific asset class risk. To mitigate concentration and other risks, assets are invested across multiple asset classes with active investment managers and passive index funds.

The company does not prefund its OPEB obligations.

Cash Contributions and Benefit Payments In 2014, the company contributed \$99 and \$293 to its U.S. and international pension plans, respectively. In 2015, the company expects contributions to be approximately \$350 to its U.S. plan and \$250 to its international pension plans. Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments and other economic factors. Additional funding may ultimately be required if investment returns are insufficient to offset increases in plan obligations.

The company anticipates paying other postretirement benefits of approximately \$198 in 2015; \$200 was paid in 2014.

The following benefit payments, which include estimated future service, are expected to be paid by the company in the next 10 years:

	Pension Benefits		Other Benefits
	U.S.	Int'l.	
2015	\$ 1,398	\$ 225	\$ 198
2016	\$ 1,346	\$ 315	\$ 203
2017	\$ 1,347	\$ 322	\$ 207
2018	\$ 1,340	\$ 355	\$ 212
2019	\$ 1,319	\$ 374	\$ 216
2020-2024	\$ 5,966	\$ 2,004	\$ 1,113

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP). Compensation expense for the ESIP totaled \$316, \$163 and \$243 in 2014, 2013 and 2012, respectively. The amounts for ESIP expense in 2013 and 2012 are net of \$140 and \$43, respectively, which reflect the value of common stock released from the former leveraged employee stock ownership plan (LESOP). LESOP debt was retired in 2013, and all remaining shares were released.

Benefit Plan Trusts Prior to its acquisition by Chevron, Texaco established a benefit plan trust for funding obligations under some of its benefit plans. At year-end 2014, the trust contained 14.2 million shares of Chevron treasury stock. The trust will sell the shares or use the dividends from the shares to pay benefits only to the extent that the company does not pay such benefits. The company intends to continue to pay its obligations under the benefit plans. The trustee will vote the shares held in the trust as instructed by the trust's beneficiaries. The shares held in the trust are not considered outstanding for earnings-per-share purposes until distributed or sold by the trust in payment of benefit obligations.

Prior to its acquisition by Chevron, Unocal established various grantor trusts to fund obligations under some of its benefit plans, including the deferred compensation and supplemental retirement plans. At December 31, 2014 and 2013, trust assets of \$38 and \$40, respectively, were invested primarily in interest-earning accounts.

Employee Incentive Plans The Chevron Incentive Plan is an annual cash bonus plan for eligible employees that links awards to corporate, business unit and individual performance in the prior year. Charges to expense for cash bonuses were \$965, \$871 and \$898 in 2014, 2013 and 2012, respectively. Chevron also has the LTIP for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 21, beginning on page 58.

Note 23

Other Contingencies and Commitments

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. Refer to Note 16, beginning on page 53, for a discussion of the periods for which tax returns have been audited for the company's major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return.

Settlement of open tax years, as well as other tax issues in countries where the company conducts its businesses, are not expected to have a material effect on the consolidated financial position or liquidity of the company and, in the opinion of management, adequate provision has been made for income and franchise taxes for all years under examination or subject to future examination.

Guarantees The company's guarantee of \$485 is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 13-year remaining term of the guarantee, the maximum guarantee amount will be reduced as certain fees are paid by the affiliate. There are numerous cross-indemnity agreements with the affiliate and the other partners to permit recovery of amounts paid under the guarantee. Chevron has recorded no liability for its obligation under this guarantee.

Indemnifications In the acquisition of Unocal, the company assumed certain indemnities relating to contingent environmental liabilities associated with assets that were sold in 1997. The acquirer of those assets shared in certain environmental remediation costs up to a maximum obligation of \$200, which had been reached at December 31, 2009. Under the indemnification agreement, after reaching the \$200 obligation, Chevron is solely responsible until April 2022, when the indemnification expires. The environmental conditions or events that are subject to these indemnities must have arisen prior to the sale of the assets in 1997.

Although the company has provided for known obligations under this indemnity that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements

The company and its subsidiaries have certain contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate

approximate amounts of required payments under these various commitments are: 2015 – \$3,600; 2016 – \$3,000; 2017 – \$2,300; 2018 – \$2,100; 2019 – \$1,600; 2020 and after – \$4,500. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$3,700 in 2014, \$3,600 in 2013 and \$3,600 in 2012.

Environmental The company is subject to loss contingencies pursuant to laws, regulations, private claims and legal proceedings related to environmental matters that are subject to legal settlements or that in the future may require the company to take action to correct or ameliorate the effects on the environment of prior release of chemicals or petroleum substances, including MTBE, by the company or other parties. Such contingencies may exist for various sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, crude oil fields, service stations, terminals, land development areas, and mining operations, whether operating, closed or divested. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Although the company has provided for known environmental obligations that are probable and reasonably estimable, the amount of additional future costs may be material to results of operations in the period in which they are recognized. The company does not expect these costs will have a material effect on its consolidated financial position or liquidity. Also, the company does not believe its obligations to make such expenditures have had, or will have, any significant impact on the company's competitive position relative to other U.S. or international petroleum or chemical companies.

Chevron's environmental reserve as of December 31, 2014, was \$1,683. Included in this balance were remediation activities at approximately 164 sites for which the company had been identified as a potentially responsible party or otherwise involved in the remediation by the U.S. Environmental Protection Agency (EPA) or other regulatory agencies under the provisions of the federal Superfund law or analogous state laws. The company's remediation reserve for these sites at year-end 2014 was \$456. The federal Superfund law and analogous state laws provide for joint and several liability for all responsible parties. Any future actions by the EPA or other regulatory agencies to require Chevron to assume other potentially responsible parties' costs at designated hazardous waste sites are not expected to have a material effect on the company's results of operations, consolidated financial position or liquidity.

Of the remaining year-end 2014 environmental reserves balance of \$1,227, \$868 related to the company's U.S. downstream operations, including refineries and other plants, marketing locations (i.e., service stations and terminals), chemical facilities, and pipelines. The remaining \$359 was associated with various sites in international downstream \$79, upstream \$275 and other businesses \$5. Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both. These and other activities include one or more of the following: site assessment; soil excavation; offsite disposal of contaminants; onsite containment, remediation and/or extraction of petroleum hydrocarbon liquid and vapor from soil; groundwater extraction and treatment; and monitoring of the natural attenuation of the contaminants.

The company manages environmental liabilities under specific sets of regulatory requirements, which in the United States include the Resource Conservation and Recovery Act and various state and local regulations. No single remediation site at year-end 2014 had a recorded liability that was material to the company's results of operations, consolidated financial position or liquidity.

It is likely that the company will continue to incur additional liabilities, beyond those recorded, for environmental remediation relating to past operations. These future costs are not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions that may be required, the determination of the company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Refer to Note 24 for a discussion of the company's asset retirement obligations.

Other Contingencies On April 26, 2010, a California appeals court issued a ruling related to the adequacy of an Environmental Impact Report (EIR) supporting the issuance of certain permits by the city of Richmond, California, to replace and upgrade certain facilities at Chevron's refinery in Richmond. Settlement discussions with plaintiffs in the case ended late fourth quarter 2010, and on March 3, 2011, the trial court entered a final judgment and peremptory writ ordering the City to set aside the project EIR and conditional use permits and enjoining Chevron from any further work. On May 23, 2011, the company filed an application with the City Planning Department for a conditional use permit for a revised project to complete construction of the hydrogen plant, certain sulfur removal facilities and related infrastructure.

On June 10, 2011, the City published its Notice of Preparation of the revised EIR for the project, and on March 18, 2014, the revised draft EIR was published for public comment. The public comment period closed in May 2014, the final EIR was released on June 9, 2014, and on July 29, 2014, the Richmond City Council certified the EIR and approved a conditional use permit. The company is now seeking to secure the further necessary approvals to resume construction. Although the City Council has certified the EIR, management believes the outcomes associated with the project are uncertain. Due to the uncertainty of the company's future course of action, or potential outcomes of any action or combination of actions, management does not believe an estimate of the financial effects, if any, can be made at this time.

Chevron receives claims from and submits claims to customers; trading partners; U.S. federal, state and local regulatory bodies; governments; contractors; insurers; and suppliers. The amounts of these claims, individually and in the aggregate, may be significant and take lengthy periods to resolve.

The company and its affiliates also continue to review and analyze their operations and may close, abandon, sell, exchange, acquire or restructure assets to achieve operational or strategic benefits and to improve competitiveness and profitability. These activities, individually or together, may result in gains or losses in future periods.

Note 24

Asset Retirement Obligations

The company records the fair value of a liability for an asset retirement obligation (ARO) as an asset and liability when there is a legal obligation associated with the retirement of a tangible long-lived asset and the liability can be reasonably estimated. The legal obligation to perform the asset retirement activity is unconditional, even though uncertainty may exist about the timing and/or method of settlement that may be beyond the company's control. This uncertainty about the timing and/or method of settlement is factored into the measurement of the liability when sufficient information exists to reasonably estimate fair value. Recognition of the ARO includes: (1) the present value of a liability and offsetting asset, (2) the subsequent accretion of that liability and depreciation of the asset, and (3) the periodic review of the ARO liability estimates and discount rates.

AROs are primarily recorded for the company's crude oil and natural gas producing assets. No significant AROs associated with any legal obligations to retire downstream long-lived assets have been recognized, as indeterminate settlement dates for the asset retirements prevent estimation of the fair value of the associated ARO. The company performs periodic reviews of its downstream long-lived assets for any changes in facts and circumstances that might require recognition of a retirement obligation.

The following table indicates the changes to the company's before-tax asset retirement obligations in 2014, 2013 and 2012:

	2014	2013	2012
Balance at January 1	\$ 14,298	\$ 13,271	\$ 12,767
Liabilities incurred	133	59	133
Liabilities settled	(1,291)	(907)	(966)
Accretion expense	882	627	629
Revisions in estimated cash flows	1,031	1,248	708
Balance at December 31	\$ 15,053	\$ 14,298	\$ 13,271

In the table above, the amounts associated with "Revisions in estimated cash flows" generally reflect increasing costs for complex well abandonments and accelerated timing of abandonment. The long-term portion of the \$15,053 balance at the end of 2014 was \$14,246.

Note 25

Other Financial Information

Earnings in 2014 included after-tax gains of approximately \$3,000 relating to the sale of nonstrategic properties. Of this amount, approximately \$1,800, \$1,000 and \$200 related to upstream, downstream, and other assets, respectively. Earnings in 2013 included after-tax gains of approximately \$500 relating to the sale of nonstrategic properties. Of this amount, approximately \$300 and \$200 related to downstream and upstream assets, respectively. Earnings in 2014 included after-tax charges of approximately \$1,000 for impairments and other asset write-offs, of which \$800 was related to upstream and \$200 to a mining asset. Earnings in 2013 included after-tax charges of approximately \$400 for impairments and other asset write-offs, of which \$300 was related to upstream and \$100 to other assets and investments.

Other financial information is as follows:

	Year ended December 31		
	2014	2013	2012
Total financing interest and debt costs	\$ 358	\$ 284	\$ 242
Less: Capitalized interest	358	284	242
Interest and debt expense	\$ —	\$ —	\$ —
Research and development expenses	\$ 707	\$ 750	\$ 648
Excess of replacement cost over the carrying value of inventories (LIFO method)	8,135	9,150	9,292
LIFO profits on inventory drawdowns included in earnings	13	14	121
Foreign currency effects*	\$ 487	\$ 474	\$ (454)

* Includes \$118, \$244 and \$(202) in 2014, 2013 and 2012, respectively, for the company's share of equity affiliates' foreign currency effects.

The company has \$4,593 in goodwill on the Consolidated Balance Sheet related to the 2005 acquisition of Unocal and to the 2011 acquisition of Atlas Energy, Inc. The company tested this goodwill for impairment during 2014 and concluded no impairment was necessary.

Five Year Financial Summary

Unaudited

Millions of dollars, except per-share amounts	2014	2013	2012	2011	2010
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues*	\$ 200,494	\$ 220,156	\$ 230,590	\$ 244,371	\$ 198,198
Income from equity affiliates and other income	11,476	8,692	11,319	9,335	6,730
Total Revenues and Other Income	211,970	228,848	241,909	253,706	204,928
Total Costs and Other Deductions					
Income Before Income Tax Expense	31,202	35,905	46,332	47,634	32,055
Income Tax Expense	11,892	14,308	19,996	20,626	12,919
Net Income	19,310	21,597	26,336	27,008	19,136
Less: Net income attributable to noncontrolling interests	69	174	157	113	112
Net Income Attributable to Chevron Corporation	\$ 19,241	\$ 21,423	\$ 26,179	\$ 26,895	\$ 19,024
Per Share of Common Stock					
Net Income Attributable to Chevron					
– Basic	\$ 10.21	\$ 11.18	\$ 13.42	\$ 13.54	\$ 9.53
– Diluted	\$ 10.14	\$ 11.09	\$ 13.32	\$ 13.44	\$ 9.48
Cash Dividends Per Share	\$ 4.21	\$ 3.90	\$ 3.51	\$ 3.09	\$ 2.84
Balance Sheet Data (at December 31)					
Current assets	\$ 42,232	\$ 50,250	\$ 55,720	\$ 53,234	\$ 48,841
Noncurrent assets	223,794	203,503	177,262	156,240	135,928
Total Assets	266,026	253,753	232,982	209,474	184,769
Short-term debt	3,790	374	127	340	187
Other current liabilities	28,136	32,644	34,085	33,260	28,825
Long-term debt and capital lease obligations	24,028	20,057	12,065	9,812	11,289
Other noncurrent liabilities	53,881	50,251	48,873	43,881	38,657
Total Liabilities	109,835	103,326	95,150	87,293	78,958
Total Chevron Corporation Stockholders' Equity	\$ 155,028	\$ 149,113	\$ 136,524	\$ 121,382	\$ 105,081
Noncontrolling interests	1,163	1,314	1,308	799	730
Total Equity	\$ 156,191	\$ 150,427	\$ 137,832	\$ 122,181	\$ 105,811
* Includes excise, value-added and similar taxes:	\$ 8,186	\$ 8,492	\$ 8,010	\$ 8,085	\$ 8,591

Five-Year Operating Summary

Unaudited

<i>Worldwide-Includes Equity in Affiliates</i>					
<i>Thousands of barrels per day, except natural gas data, which is millions cubic feet per day</i>					
	2014	2013	2012	2011	2010
United States					
Net production of crude oil and natural gas liquids	456	449	455	465	489
Net production of natural gas ¹	1,250	1,246	1,203	1,279	1,314
Net oil-equivalent production	664	657	655	678	708
Refinery input	871	774	833	854	890
Sales of refined products	1,210	1,182	1,211	1,257	1,349
Sales of natural gas liquids	141	142	157	161	161
Total Sales of petroleum products	1,351	1,324	1,368	1,418	1,510
Sales of natural gas	3,995	5,483	5,470	5,836	5,932
International					
Net production of crude oil and natural gas liquids ²	1,253	1,282	1,309	1,384	1,434
Net production of natural gas ¹	3,917	3,946	3,871	3,662	3,726
Net oil-equivalent production	1,907	1,940	1,955	1,995	2,055
Refinery input ³	819	864	869	933	1,004
Sales of refined products ⁴	1,501	1,529	1,554	1,692	1,764
Sales of natural gas liquids	86	88	88	87	105
Total sales of petroleum products	1,587	1,617	1,642	1,779	1,869
Sales of natural gas	4,304	4,251	4,315	4,361	4,493
Total Worldwide					
Net production of crude oil and natural gas liquids	1,709	1,731	1,764	1,849	1,923
Net production of natural gas	5,167	5,192	5,074	4,941	5,040
Net oil-equivalent production	2,571	2,597	2,610	2,673	2,763
Refinery input	1,690	1,638	1,702	1,787	1,894
Sales of refined products	2,711	2,711	2,765	2,949	3,113
Sales of natural gas liquids	227	230	245	248	266
Total sales of petroleum products	2,938	2,941	3,010	3,197	3,379
Sales of natural gas	8,299	9,734	9,785	10,197	10,425
Worldwide - Excludes Equity in Affiliates Number of completed wells (net) ⁵					
Oil and gas	2,246	1,833	1,618	1,551	1,160
Dry	27	20	19	19	31
Productive oil and gas wells (net) ⁵	56,678	56,635	55,812	55,049	51,677
¹ Includes natural gas consumed in operations:					
United States	71	72	65	69	62
International ⁶	452	458	457	447	475
Total ⁶	523	530	522	516	537
² Includes: Canada-synthetic oil					
	43	43	43	40	24
Venezuela affiliate-synthetic oil					
	31	25	17	32	28
³ As of June 2012, Star Petroleum Refining Company crude-input volumes are reported on a 100 percent consolidated basis. Prior to June 2012, crude-input volumes reflect a 64 percent equity interest.					
⁴ Includes sales of affiliates (MBPD):					
	475	471	522	556	562
⁵ Net wells include wholly owned and the sum of fractional interests in partially owned wells					
⁶ 2013 conforms to 2014 presentation					

In accordance with FASB and SEC disclosure requirements for oil and gas producing activities, this section provides supplemental information on oil and gas exploration and producing activities of the company in seven separate tables. Tables I through IV provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables V through VII present information on the company's estimated net proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved

Table I - Costs Incurred in Exploration, Property Acquisitions and Development¹

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2014									
Exploration									
Wells	\$ 965	\$ 87	\$ 436	\$ 381	\$ 207	\$ 101	\$ 2,177	\$ —	\$ —
Geological and geophysical	107	72	32	64	88	41	404	—	—
Rentals and other	150	37	198	98	101	103	687	—	—
Total exploration	1,222	196	666	543	396	245	3,268	—	—
Property acquisitions ²									
Proved	33	1	521	60	—	—	615	—	—
Unproved	196	2	39	—	—	—	237	—	—
Total property acquisitions	229	3	560	60	—	—	852	—	—
Development ³	8,207	3,226	3,771	4,363	7,182	887	27,636	1,598	393
Total Costs Incurred⁴	\$ 9,658	\$ 3,425	\$ 4,997	\$ 4,966	\$ 7,578	\$ 1,132	\$ 31,756	\$ 1,598	\$ 393
Year Ended December 31, 2013									
Exploration									
Wells	\$ 594	\$ 495	\$ 88	\$ 405	\$ 262	\$ 123	\$ 1,967	\$ —	\$ —
Geological and geophysical	134	70	105	116	29	55	509	—	—
Rentals and other	166	62	147	80	124	131	710	—	—
Total exploration	894	627	340	601	415	309	3,186	—	—
Property acquisitions ²									
Proved	71	—	26	64	—	1	162	—	—
Unproved	331	2,068	—	203	105	3	2,710	—	—
Total property acquisitions	402	2,068	26	267	105	4	2,872	—	—
Development ³	7,457	2,306	3,549	4,907	6,611	1,046	25,876	1,027	544
Total Costs Incurred⁴	\$ 8,753	\$ 5,001	\$ 3,915	\$ 5,775	\$ 7,131	\$ 1,359	\$ 31,934	\$ 1,027	\$ 544
Year Ended December 31, 2012									
Exploration									
Wells	\$ 251	\$ 202	\$ 121	\$ 271	\$ 302	\$ 88	\$ 1,235	\$ —	\$ —
Geological and geophysical	99	105	107	86	47	58	502	—	—
Rentals and other	161	55	93	201	85	107	702	—	—
Total exploration	511	362	321	558	434	253	2,439	—	—
Property acquisitions ²									
Proved	248	—	8	39	—	—	295	—	—
Unproved	1,150	29	5	342	28	—	1,554	—	28
Total property acquisitions	1,398	29	13	381	28	—	1,849	—	28
Development ³	6,597	1,211	3,118	3,797	5,379	753	20,855	660	293
Total Costs Incurred⁴	\$ 8,506	\$ 1,602	\$ 3,452	\$ 4,736	\$ 5,841	\$ 1,006	\$ 25,143	\$ 660	\$ 321

¹ Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 24, "Asset Retirement Obligations," on page 67.

² Does not include properties acquired in nonmonetary transactions.

³ Includes \$349, \$661, and \$963 costs incurred prior to assignment of proved reserves for consolidated companies in 2014, 2013, and 2012, respectively.

⁴ Reconciliation of consolidated and affiliated companies total cost incurred to Upstream capital and exploratory (C&E) expenditures - \$ billions.

	2014	2013	2012	
Total cost incurred	\$ 33.7	\$ 33.5	\$ 26.1	
Non-oil and gas activities	4.6	5.8	5.0	(Primarily includes LNG, gas-to-liquids and transportation activities)
ARO	(1.2)	(1.4)	(0.7)	
Upstream C&E	\$ 37.1	\$ 37.9	\$ 30.4	Reference Page 21 Upstream total

reserves and changes in estimated discounted future net cash flows. The amounts for consolidated companies are organized by geographic areas including the United States, Other Americas, Africa, Asia, Australia/Oceania and Europe. Amounts for affiliated companies include Chevron's equity interests in Tengizchevroil (TCO) in the Republic of Kazakhstan and in other affiliates, principally in Venezuela and Angola. Refer to Note 13, beginning on page 48, for a discussion of the company's major equity affiliates.

Table II - Capitalized Costs Related to Oil and Gas Producing Activities

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
At December 31, 2014									
Unproved properties	\$ 10,095	\$ 3,207	\$ 286	\$ 1,933	\$ 1,990	\$ 33	\$ 17,544	\$ 108	\$ —
Proved properties and related producing assets	75,511	14,697	33,117	47,007	3,303	9,172	182,807	7,370	3,713
Support equipment	1,670	361	1,193	1,791	796	186	5,997	1,331	—
Deferred exploratory wells	1,012	220	647	734	1,330	252	4,195	—	—
Other uncompleted projects	7,714	5,566	6,691	5,997	23,487	1,841	51,296	2,679	458
Gross Capitalized Costs	96,002	24,051	41,934	57,462	30,906	11,484	261,839	11,488	4,171
Unproved properties valuation	1,332	796	213	634	46	33	3,054	48	—
Proved producing properties – Depreciation and depletion	48,315	6,516	19,729	31,207	2,259	7,540	115,566	3,295	845
Support equipment depreciation	711	203	694	1,276	202	159	3,245	611	—
Accumulated provisions	50,358	7,515	20,636	33,117	2,507	7,732	121,865	3,954	845
Net Capitalized Costs	\$ 45,644	\$ 16,536	\$ 21,298	\$ 24,345	\$ 28,399	\$ 3,752	\$ 139,974	\$ 7,534	\$ 3,326
At December 31, 2013									
Unproved properties	\$ 10,228	\$ 3,697	\$ 267	\$ 2,064	\$ 1,990	\$ 36	\$ 18,282	\$ 109	\$ 29
Proved properties and related producing assets	67,837	12,868	32,936	42,780	3,274	9,592	169,287	6,977	3,408
Support equipment	1,314	344	1,180	1,678	1,608	177	6,301	1,166	—
Deferred exploratory wells	670	297	536	335	1,134	273	3,245	—	—
Other uncompleted projects	9,149	4,175	4,424	5,998	16,000	1,390	41,136	1,638	404
Gross Capitalized Costs	89,198	21,381	39,343	52,855	24,006	11,468	238,251	9,890	3,841
Unproved properties valuation	1,243	707	203	389	6	31	2,579	45	10
Proved producing properties – Depreciation and depletion	45,756	5,695	18,051	27,356	2,083	7,825	106,766	2,672	696
Support equipment depreciation	656	189	647	1,177	384	149	3,202	538	—
Accumulated provisions	\$ 47,655	\$ 6,591	\$ 18,901	\$ 28,922	\$ 2,473	\$ 8,005	\$ 112,547	\$ 3,255	\$ 706
Net Capitalized Costs	\$ 41,543	\$ 14,790	\$ 20,442	\$ 23,933	\$ 21,533	\$ 3,463	\$ 125,704	\$ 6,635	\$ 3,135
At December 31, 2012									
Unproved properties	\$ 10,478	\$ 1,415	\$ 271	\$ 2,039	\$ 1,884	\$ 34	\$ 16,121	\$ 109	\$ 28
Proved properties and related producing assets	62,274	11,237	30,106	39,889	2,420	9,994	155,920	6,832	1,852
Support equipment	1,179	330	1,195	1,554	1,191	172	5,621	1,089	—
Deferred exploratory wells	412	201	598	326	911	233	2,681	—	—
Other uncompleted projects	7,203	3,211	3,466	4,123	10,578	768	29,349	906	1,594
Gross Capitalized Costs	81,546	16,394	35,636	47,931	16,984	11,201	209,692	8,936	3,474
Unproved properties valuation	1,121	634	201	253	2	28	2,239	41	—
Proved producing properties – Depreciation and depletion	42,224	5,288	15,566	24,432	1,832	8,255	97,597	2,274	551
Support equipment depreciation	589	178	613	1,101	305	137	2,923	480	—
Accumulated provisions	43,934	6,100	16,380	25,786	2,139	8,420	102,759	2,795	551
Net Capitalized Costs	\$ 37,612	\$ 10,294	\$ 19,256	\$ 22,145	\$ 14,845	\$ 2,781	\$ 106,933	\$ 6,141	\$ 2,923

Table III - Results of Operations for Oil and Gas Producing Activities¹

The company's results of operations from oil and gas producing activities for the years 2014, 2013 and 2012 are shown in the following table. Net income from exploration and production activities as reported on page 46 reflects income taxes computed on an effective rate basis.

Income taxes in Table III are based on statutory tax rates, reflecting allowable deductions and tax credits. Interest income and expense are excluded from the results reported in Table III and from the net income amounts on page 46.

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2014									
Revenues from net production									
Sales	\$ 2,660	\$ 1,338	\$ 707	\$ 8,290	\$ 1,466	\$ 1,037	\$ 15,498	\$ 7,717	\$ 1,733
Transfers	13,023	2,285	12,546	8,153	888	1,277	38,172	—	—
Total	15,683	3,623	13,253	16,443	2,354	2,314	53,670	7,717	1,733
Production expenses excluding taxes	(4,786)	(1,328)	(2,084)	(4,527)	(191)	(773)	(13,689)	(493)	(670)
Taxes other than on income	(654)	(122)	(140)	(82)	(329)	(4)	(1,331)	(344)	(418)
Proved producing properties:									
Depreciation and depletion	(4,605)	(793)	(3,092)	(3,977)	(208)	(351)	(13,026)	(567)	(175)
Accretion expense ²	(334)	(22)	(130)	(142)	(32)	(84)	(744)	(9)	(4)
Exploration expenses	(581)	(119)	(383)	(309)	(269)	(281)	(1,942)	—	(5)
Unproved properties valuation	(140)	(219)	(12)	(289)	(40)	(3)	(703)	—	(38)
Other income (expense) ³	654	674	221	115	102	358	2,124	(28)	(85)
Results before income taxes	5,237	1,694	7,633	7,232	1,387	1,176	24,359	6,276	338
Income tax expense	(1,955)	(471)	(4,924)	(3,604)	(392)	(579)	(11,925)	(1,883)	(284)
Results of Producing Operations	\$ 3,282	\$ 1,223	\$ 2,709	\$ 3,628	\$ 995	\$ 597	\$ 12,434	\$ 4,393	\$ 54
Year Ended December 31, 2013									
Revenues from net production									
Sales	\$ 2,303	\$ 1,351	\$ 702	\$ 9,220	\$ 1,431	\$ 1,345	\$ 16,352	\$ 8,522	\$ 2,100
Transfers	14,471	1,973	14,804	9,521	984	1,701	43,454	—	—
Total	16,774	3,324	15,506	18,741	2,415	3,046	59,806	8,522	2,100
Production expenses excluding taxes	(4,606)	(1,218)	(2,099)	(4,429)	(193)	(759)	(13,304)	(401)	(444)
Taxes other than on income	(648)	(90)	(149)	(140)	(378)	(3)	(1,408)	(439)	(704)
Proved producing properties:									
Depreciation and depletion	(4,039)	(440)	(2,747)	(3,602)	(342)	(416)	(11,586)	(518)	(179)
Accretion expense ²	(223)	(22)	(125)	(114)	(28)	(79)	(591)	(9)	(14)
Exploration expenses	(555)	(372)	(203)	(272)	(161)	(258)	(1,821)	—	—
Unproved properties valuation	(129)	(84)	(13)	(141)	(4)	(5)	(376)	—	(10)
Other income (expense) ³	242	(5)	145	(275)	89	13	209	(81)	462
Results before income taxes	6,816	1,093	10,315	9,768	1,398	1,539	30,929	7,074	1,211
Income tax expense	(2,471)	(289)	(6,545)	(4,824)	(411)	(1,058)	(15,598)	(2,122)	(624)
Results of Producing Operations	\$ 4,345	\$ 804	\$ 3,770	\$ 4,944	\$ 987	\$ 481	\$ 15,331	\$ 4,952	\$ 587

¹ The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

² Represents accretion of ARO liability. Refer to Note 24, "Asset Retirement Obligations," on page 67.

³ Includes foreign currency gains and losses, gains and losses on property dispositions and other miscellaneous income and expenses.

Table III - Results of Operations for Oil and Gas Producing Activities¹, continued

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2012									
Revenues from net production									
Sales	\$ 1,832	\$ 1,561	\$ 1,480	\$ 10,485	\$ 1,539	\$ 1,618	\$ 18,515	\$ 7,869	\$ 1,951
Transfers	15,122	1,997	15,033	9,071	1,073	2,148	44,444	—	—
Total	16,954	3,558	16,513	19,556	2,612	3,766	62,959	7,869	1,951
Production expenses excluding taxes	(4,009)	(1,073)	(1,918)	(4,545)	(164)	(637)	(12,346)	(463)	(442)
Taxes other than on income	(654)	(123)	(161)	(191)	(390)	(3)	(1,522)	(439)	(767)
Proved producing properties:									
Depreciation and depletion	(3,462)	(508)	(2,475)	(3,399)	(315)	(541)	(10,700)	(427)	(147)
Accretion expense ²	(226)	(33)	(66)	(92)	(23)	(46)	(486)	(8)	(6)
Exploration expenses	(244)	(145)	(427)	(489)	(133)	(272)	(1,710)	—	—
Unproved properties valuation	(127)	(138)	(16)	(133)	—	(15)	(429)	—	—
Other income (expense) ³	167	(169)	(199)	245	2,495	13	2,552	27	31
Results before income taxes	8,399	1,369	11,251	10,952	4,082	2,265	38,318	6,559	620
Income tax expense	(3,043)	(310)	(7,558)	(5,739)	(1,226)	(1,511)	(19,387)	(1,972)	(299)
Results of Producing Operations	\$ 5,356	\$ 1,059	\$ 3,693	\$ 5,213	\$ 2,856	\$ 754	\$ 18,931	\$ 4,587	\$ 321

¹ The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

² Represents accretion of ARO liability. Refer to Note 24, "Asset Retirement Obligations," on page 67.

³ Includes foreign currency gains and losses, gains and losses on property dispositions, and other miscellaneous income and expenses.

Table IV - Results of Operations for Oil and Gas Producing Activities - Unit Prices and Costs¹

	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2014									
Average sales prices									
Liquids, per barrel	\$ 84.13	\$ 83.57	\$ 96.43	\$ 89.44	\$ 95.17	\$ 95.05	\$ 89.44	\$ 81.07	\$ 76.07
Natural gas, per thousand cubic feet	3.90	2.84	1.53	5.86	10.42	9.29	5.44	1.53	6.38
Average production costs, per barrel ²	20.09	22.77	13.77	17.21	5.53	27.14	17.69	4.47	29.30
Year Ended December 31, 2013									
Average sales prices									
Liquids, per barrel	\$ 93.46	\$ 88.32	\$ 107.22	\$ 98.37	\$ 103.28	\$ 105.78	\$ 99.05	\$ 88.06	\$ 78.87
Natural gas, per thousand cubic feet	3.38	2.68	1.76	6.02	10.61	11.04	5.45	1.50	4.00
Average production costs, per barrel ²	19.57	21.29	13.93	16.49	5.90	22.87	17.10	4.37	22.69
Year Ended December 31, 2012									
Average sales prices									
Liquids, per barrel	\$ 95.21	\$ 87.87	\$ 109.64	\$ 102.46	\$ 103.06	\$ 108.77	\$ 101.61	\$ 89.34	\$ 83.97
Natural gas, per thousand cubic feet	2.65	3.59	1.22	6.03	10.99	10.10	5.42	1.36	5.39
Average production costs, per barrel ²	16.99	18.38	12.14	16.71	4.86	15.72	15.46	4.42	18.73

¹ The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.

² Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.

Table V Reserve Quantity Information

Summary of Net Oil and Gas Reserves

	2014			2013			2012		
<i>Liquids in Millions of Barrels</i> <i>Natural Gas in Billions of Cubic Feet</i>	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas	Crude Oil Condensate NGLs	Synthetic Oil	Natural Gas
Proved Developed									
Consolidated Companies									
U.S.	955	—	2,743	976	—	2,632	1,012	—	2,574
Other Americas	103	531	739	109	403	943	91	391	1,063
Africa	701	—	1,112	763	—	1,161	782	—	1,163
Asia	584	—	4,607	601	—	4,620	643	—	4,511
Australia/Oceania	38	—	1,117	44	—	1,251	31	—	682
Europe	87	—	167	94	—	200	103	—	191
Total Consolidated	2,468	531	10,485	2,587	403	10,807	2,662	391	10,184
Affiliated Companies									
TCO	961	—	1,431	884	—	1,188	977	—	1,261
Other	100	51	317	105	44	330	115	50	377
Total Consolidated and Affiliated Companies	3,529	582	12,233	3,576	447	12,325	3,754	441	11,822
Proved Undeveloped									
Consolidated Companies									
U.S.	477	—	1,431	354	—	1,358	347	—	1,148
Other Americas	135	3	384	134	134	357	132	122	412
Africa	320	—	1,856	341	—	1,884	348	—	1,918
Asia	168	—	1,659	191	—	2,125	194	—	2,356
Australia/Oceania	104	—	9,824	87	—	9,076	103	—	9,570
Europe	79	—	68	72	—	63	54	—	66
Total Consolidated	1,283	3	15,222	1,179	134	14,863	1,178	122	15,470
Affiliated Companies									
TCO	654	—	746	784	—	1,102	755	—	1,038
Other	45	153	915	49	176	856	49	182	865
Total Consolidated and Affiliated Companies	1,982	156	16,883	2,012	310	16,821	1,982	304	17,373
Total Proved Reserves	5,511	738	29,116	5,588	757	29,146	5,736	745	29,195

Reserves Governance The company has adopted a comprehensive reserves and resource classification system modeled after a system developed and approved by the Society of Petroleum Engineers, the World Petroleum Congress and the American Association of Petroleum Geologists. The system classifies recoverable hydrocarbons into six categories based on their status at the time of reporting - three deemed commercial and three potentially recoverable. Within the commercial classification are proved reserves and two categories of unproved: probable and possible. The potentially recoverable categories are also referred to as contingent resources. For reserves estimates to be classified as proved, they must meet all SEC and company standards.

Proved oil and gas reserves are the estimated quantities that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in the future from known reservoirs under existing economic conditions, operating methods and government regulations. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

Proved reserves are classified as either developed or undeveloped. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods.

Due to the inherent uncertainties and the limited nature of reservoir data, estimates of reserves are subject to change as additional information becomes available.

Proved reserves are estimated by company asset teams composed of earth scientists and engineers. As part of the internal control process related to reserves estimation, the company maintains a Reserves Advisory Committee (RAC) that is chaired by the Manager of Corporate Reserves, a corporate department that reports directly to the Vice Chairman responsible for the company's worldwide exploration and production activities. The Manager of Corporate Reserves has more than 30 years' experience working in the oil and gas industry and a Master of Science in Petroleum Engineering degree from Stanford University. His experience includes more than 15 years of managing oil and gas reserves processes. He was chairman of the Society of Petroleum Engineers Oil and Gas Reserves Committee, served on the United Nations Expert Group on Resources Classification, and is a past member of the Joint Committee on Reserves Evaluator Training and the California Conservation Committee. He is an active member of the Society of Petroleum Evaluation Engineers and serves on the Society of Petroleum Engineers Oil and Gas Reserves Committee.

All RAC members are degreed professionals, each with more than 10 years of experience in various aspects of reserves estimation relating to reservoir engineering, petroleum engineering, earth science or finance. The members are knowledgeable in SEC guidelines for proved reserves classification and receive annual training on the preparation of reserves estimates. The reserves activities are managed by two operating company-level reserves managers. These two reserves managers are not members of the RAC so as to preserve corporate-level independence.

The RAC has the following primary responsibilities: establish the policies and processes used within the operating units to estimate reserves; provide independent reviews and oversight of the business units' recommended reserves estimates and changes; confirm that proved reserves are recognized in accordance with SEC guidelines; determine that reserve volumes are calculated using consistent and appropriate standards, procedures and technology; and maintain the *Corporate Reserves Manual*, which provides standardized procedures used corporatewide for classifying and reporting hydrocarbon reserves.

During the year, the RAC is represented in meetings with each of the company's upstream business units to review and discuss reserve changes recommended by the various asset teams. Major changes are also reviewed with the company's Strategy and Planning Committee, whose members include the Chief Executive Officer and the Chief Financial Officer. The company's annual reserve activity is also reviewed with the Board of Directors. If major changes to reserves were to occur between the annual reviews, those matters would also be discussed with the Board.

RAC subteams also conduct in-depth reviews during the year of many of the fields that have large proved reserves quantities. These reviews include an examination of the proved-reserve records and documentation of their compliance with the *Corporate Reserves Manual*.

Technologies Used in Establishing Proved Reserves Additions In 2014, additions to Chevron's proved reserves were based on a wide range of geologic and engineering technologies. Information generated from wells, such as well logs, wire line sampling, production and pressure testing, fluid analysis, and core analysis, was integrated with seismic data, regional geologic studies, and information from analogous reservoirs to provide "reasonably certain" proved reserves estimates. Both proprietary and commercially available analytic tools, including reservoir simulation, geologic modeling and seismic processing, have been used in the interpretation of the subsurface data. These technologies have been utilized extensively by the company in the past, and the company believes that they provide a high degree of confidence in establishing reliable and consistent reserves estimates.

Proved Undeveloped Reserves At the end of 2014, proved undeveloped reserves totaled 5.0 billion barrels of oil-equivalent (BOE), a decrease of 174 million BOE from year-end 2013. The decrease was due to the transfer of 646 million BOE to proved developed and 2 million BOE in sales, partially offset by increases of 277 million BOE in extensions and discoveries, 169 million BOE in revisions, and 28 million BOE in improved recovery.

During 2014, investments totaling approximately \$15.4 billion in oil and gas producing activities and about \$2.9 billion in non-oil and gas producing activities were expended to advance the development of proved undeveloped reserves. Australia accounted for about \$7.1 billion of the total, mainly for development and construction activities at the Gorgon and Wheatstone LNG projects. Expenditures of about \$3.4 billion in the United States related primarily to various development activities in the Gulf of Mexico and the midcontinent region. In Asia, expenditures during the year totaled approximately \$3.3 billion, primarily related to development projects of the TCO affiliate in Kazakhstan, and in Thailand. In Africa, about \$2.8 billion was expended on various offshore development and natural gas projects in Nigeria and Angola. Development activities in Canada and Brazil were primarily responsible for about \$1.6 billion of expenditures in Other Americas.

Reserves that remain proved undeveloped for five or more years are a result of several factors that affect optimal project development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructure or plant capacities that dictate project timing, compression projects that are pending reservoir pressure declines, and contractual limitations that dictate production levels.

At year-end 2014, the company held approximately 2.5 billion BOE of proved undeveloped reserves that have remained undeveloped for five years or more. The majority of these reserves are in three locations where the company has a proven track record of developing major projects. In Australia, approximately 700 million BOE have remained undeveloped for five years or more related to the Gorgon Project. The company is currently constructing liquefaction and other facilities in Australia to develop this natural gas. In Africa, approximately 400 million BOE have remained undeveloped for five years or more, primarily due to facility constraints at various fields and infrastructure associated with the Escravos gas projects in Nigeria. Affiliates account for about 1.1 billion BOE of proved undeveloped reserves that have remained undeveloped for five years or more, with the majority related to the TCO affiliate in Kazakhstan. At TCO, further field development to convert the remaining proved undeveloped reserves is scheduled to occur in line with reservoir depletion.

Annually, the company assesses whether any changes have occurred in facts or circumstances, such as changes to development plans, regulations or government policies, that would warrant a revision to reserve estimates. For 2014, this assessment did not result in any material changes in reserves classified as proved undeveloped. Over the past three years, the ratio of proved undeveloped reserves to total proved reserves has ranged between 44 percent and 46 percent. The consistent completion of major capital projects has kept the ratio in a narrow range over this time period.

Proved Reserve Quantities For the three years ending December 31, 2014, the pattern of net reserve changes shown in the following tables are not necessarily indicative of future trends. Apart from acquisitions, the company's ability to add proved reserves can be affected by events and circumstances that are outside the company's control, such as delays in government permitting, partner approvals of development plans, changes in oil and gas prices, OPEC constraints, geopolitical uncertainties, and civil unrest.

At December 31, 2014, proved reserves for the company were 11.1 billion BOE. The company's estimated net proved reserves of liquids including crude oil, condensate, natural gas liquids and synthetic oil for the years 2012, 2013 and 2014 are shown in the table on page 77. The company's estimated net proved reserves of natural gas are shown on page 78.

Noteworthy changes in liquids proved reserves for 2012 through 2014 are discussed below and shown in the table on the following page:

Revisions In 2012, improved field performance and drilling associated with Gulf of Mexico projects accounted for the majority of the 104 million barrel increase in the United States. In Asia, drilling results across numerous assets drove the 97 million barrel increase. Improved field performance from various Nigeria and Angola producing assets was primarily responsible for the 66 million barrel increase in Africa. Improved plant efficiency for the TCO affiliate was responsible for a large portion of the 59 million barrel increase.

In 2013, improved field performance from various Nigeria and Angola producing assets was primarily responsible for the 94 million barrel increase in Africa. In Asia, drilling performance across numerous assets resulted in an 84 million barrel increase. Improved field performance and drilling associated with Gulf of Mexico projects and drilling in the Midland and Delaware basins accounted for the majority of the 55 million barrel increase in the United States. Synthetic oil reserves in Canada increased by 40 million barrels, primarily due to improved field performance.

In 2014, drilling in the Midland and Delaware basins and improved field performance and drilling in California accounted for the majority of the 90 million barrel increase in the United States. Improved field performance at various Nigeria fields was primarily responsible for the 74 million barrel increase in Africa. In Asia, drilling performance across numerous assets, primarily in Indonesia, resulted in the 80 million barrel increase.

Improved Recovery In 2012, improved recovery increased reserves by 77 million barrels, primarily due to secondary recovery performance in Africa and in Gulf of Mexico fields in the United States.

In 2013, improved recovery increased reserves by 57 million barrels due to numerous small projects, including expansions of existing projects in the United States, Europe, Asia, and Africa.

In 2014, improved recovery increased reserves by 34 million barrels, primarily due to secondary recovery projects in the United States, mostly related to steamflood expansions in California.

Extensions and Discoveries In 2012, extensions and discoveries increased reserves 101 million barrels in Other Americas, primarily due to the initial booking of the Hebron project in Canada. In the United States, additions at several Gulf of Mexico projects and drilling activities in the mid-continent region were primarily responsible for the 77 million barrel increase.

In 2013, extensions and discoveries in the Midland and Delaware basins were primarily responsible for the 55 million barrel increase in the United States.

In 2014, extensions and discoveries in the Midland and Delaware basins and the Gulf of Mexico were primarily responsible for the 164 million barrel increase in the United States.

Purchases In 2014, the purchase of additional reserves in Canada was responsible for the 26 million barrel increase in synthetic oil.

Sales In 2014, the sale of the company's interests in Chad was responsible for the 20 million barrel decrease in Africa.

Net Proved Reserves of Crude Oil, Condensate, Natural Gas Liquids and Synthetic Oil

Millions of barrels	Consolidated Companies							Affiliated Companies			Total Consolidated and Affiliated Companies	
	U.S.	Other Americas ¹	Africa	Asia	Australia/Oceania	Europe	Synthetic Oil ²	Total	TCO	Synthetic Oil		Other ³
Reserves at January 1, 2012	1,311	113	1,155	894	140	159	523	4,295	1,759	244	157	6,455
Changes attributable to:												
Revisions	104	20	66	97	4	16	6	313	59	(6)	24	390
Improved recovery	24	8	30	6	—	9	—	77	—	—	—	77
Extensions and discoveries	77	101	30	2	7	—	—	217	—	—	1	218
Purchases	10	—	—	—	—	—	—	10	—	—	—	10
Sales	(1)	—	—	(15)	(7)	—	—	(23)	—	—	—	(23)
Production	(166)	(19)	(151)	(147)	(10)	(27)	(16)	(536)	(86)	(6)	(18)	(646)
Reserves at December 31, 2012⁴	1,359	223	1,130	837	134	157	513	4,353	1,732	232	164	6,481
Changes attributable to:												
Revisions	55	25	94	84	7	17	40	322	32	(3)	3	354
Improved recovery	26	—	10	10	—	11	—	57	—	—	—	57
Extensions and discoveries	55	4	13	2	—	4	—	78	—	—	—	78
Purchases	2	9	—	—	—	—	—	11	—	—	—	11
Sales	(3)	—	(1)	—	—	—	—	(4)	—	—	—	(4)
Production	(164)	(18)	(142)	(141)	(10)	(23)	(16)	(514)	(96)	(9)	(13)	(632)
Reserves at December 31, 2013⁴	1,330	243	1,104	792	131	166	537	4,303	1,668	220	154	6,345
Changes attributable to:												
Revisions	90	—	74	80	19	9	(32)	240	41	(4)	—	277
Improved recovery	19	1	1	8	—	5	—	34	—	—	—	34
Extensions and discoveries	164	18	2	7	—	8	19	218	—	—	1	219
Purchases	1	—	—	—	—	—	26	27	—	—	—	27
Sales	(6)	—	(20)	—	—	(3)	—	(29)	—	—	—	(29)
Production	(166)	(24)	(140)	(135)	(8)	(19)	(16)	(508)	(94)	(12)	(10)	(624)
Reserves at December 31, 2014⁴	1,432	238	1,021	752	142	166	534	4,285	1,615	204	145	6,249

¹ Ending reserve balances in North America were 142, 141 and 121 and in South America were 96, 102 and 102 in 2014, 2013 and 2012, respectively.

² Reserves associated with Canada.

³ Ending reserve balances in Africa were 37, 37 and 41 and in South America were 108, 117 and 123 in 2014, 2013 and 2012, respectively.

⁴ Included are year-end reserve quantities related to production-sharing contracts (PSC). PSC-related reserve quantities are 19 percent, 20 percent and 20 percent for consolidated companies for 2014, 2013 and 2012, respectively.

Net Proved Reserves of Natural Gas

Billions of cubic feet (BCF)	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated Companies
	U.S.	Other Americas ¹	Africa	Asia	Australia/Oceania	Europe	Total	TCO	Other ²	
Reserves at January 1, 2012	3,646	1,664	3,196	6,721	9,744	258	25,229	2,251	1,203	28,683
Changes attributable to:										
Revisions	318	(77)	(30)	1,007	358	84	1,660	158	37	1,855
Improved recovery	5	—	—	1	—	2	8	—	—	8
Extensions and discoveries	166	34	2	50	747	—	999	—	12	1,011
Purchases	33	—	—	—	—	—	33	—	—	33
Sales	(6)	—	—	(93)	(439)	—	(538)	—	—	(538)
Production ³	(440)	(146)	(87)	(819)	(158)	(87)	(1,737)	(110)	(10)	(1,857)
Reserves at December 31, 2012	3,722	1,475	3,081	6,867	10,252	257	25,654	2,299	1,242	29,195
Changes attributable to:										
Revisions	(234)	(59)	27	627	229	46	636	117	(35)	718
Improved recovery	3	—	2	6	—	4	15	—	—	15
Extensions and discoveries	951	—	27	16	—	27	1,021	—	—	1,021
Purchases	12	32	—	60	—	—	104	—	—	104
Sales	(10)	—	(1)	—	—	(1)	(12)	—	—	(12)
Production ³	(454)	(148)	(91)	(831)	(154)	(70)	(1,748)	(126)	(21)	(1,895)
Reserves at December 31, 2013	3,990	1,300	3,045	6,745	10,327	263	25,670	2,290	1,186	29,146
Changes attributable to:										
Revisions	76	(110)	35	252	775	36	1,064	9	34	1,107
Improved recovery	2	1	1	—	—	1	5	—	—	5
Extensions and discoveries	614	56	—	79	—	3	752	—	32	784
Purchases	1	—	—	21	—	—	22	—	—	22
Sales	(53)	(1)	(3)	—	—	(5)	(62)	—	—	(62)
Production ³	(456)	(123)	(110)	(831)	(161)	(63)	(1,744)	(122)	(20)	(1,886)
Reserves at December 31, 2014	4,174	1,123	2,968	6,266	10,941	235	25,707	2,177	1,232	29,116

¹ Ending reserve balances in North America and South America were 59, 54, 49 and 1,064, 1,246, 1,426 in 2014, 2013 and 2012, respectively.

² Ending reserve balances in Africa and South America were 1,043, 1,009, 1,068 and 189, 177, 174 in 2014, 2013 and 2012, respectively.

³ Total "as sold" volumes are 1,695 BCF, 1,702 BCF and 1,666 BCF for 2014, 2013 and 2012, respectively; 2013 conformed to 2014 presentation.

⁴ Includes reserve quantities related to production-sharing contracts (PSC). PSC-related reserve quantities are 19 percent, 20 percent and 21 percent for consolidated companies for 2014, 2013 and 2012, respectively.

Noteworthy changes in natural gas proved reserves for 2012 through 2014 are discussed below and shown in the table above:

Revisions In 2012, net revisions of 1,007 BCF in Asia were primarily due to development drilling and additional compression in Bangladesh, and drilling results and improved field performance in Thailand. In Australia, updated reservoir data interpretation based on additional drilling at the Gorgon Project drove the 358 BCF increase. Drilling results from activities in the Marcellus Shale were responsible for the majority of the 318 BCF increase in the United States.

In 2013, net revisions of 627 BCF in Asia were primarily due to development drilling and improved field performance in Bangladesh and Thailand. In Australia, drilling performance drove the 229 BCF increase. The majority of the net decrease of 234 BCF in the United States was due to a change in development plans in the Appalachian region.

In 2014, net revisions of 775 BCF in Australia were primarily due to development drilling at Gorgon.

Extensions and Discoveries In 2012, extensions and discoveries of 747 BCF in Australia were primarily due to positive drilling results at the Gorgon Project.

In 2013, extensions and discoveries of 951 BCF in the United States were primarily in the Appalachian region.

In 2014, extensions and discoveries of 614 BCF in the United States were primarily in the Appalachian region and the Delaware Basin.

Sales In 2012, the sale of a portion of the company's equity interest in the Wheatstone Project was responsible for the 439 BCF reduction in Australia.

Table VI - Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows is calculated in accordance with SEC and FASB requirements. This includes using the average of first-day-of-the-month oil and gas prices for the 12-month period prior to the end of the reporting period, estimated future development and production costs assuming the continuation of existing economic conditions, estimated costs for asset retirement obligations, and estimated future income taxes based on appropriate statutory tax rates. Discounted future net cash flows are calculated using 10 percent mid-period discount factors. Estimates of proved-reserve quantities are imprecise and change over time as new information becomes available. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. The valuation requires assumptions as to the timing and amount of future development and production costs. The calculations are made as of December 31 each year and do not represent management's estimate of the company's future cash flows or value of its oil and gas reserves. In the following table, the caption "Standardized Measure Net Cash Flows" refers to the standardized measure of discounted future net cash flows.

<i>Millions of dollars</i>	Consolidated Companies						Affiliated Companies		Total Consolidated and Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia/Oceania	Europe	Total	TCO		Other
At December 31, 2014										
Future cash inflows from production	\$ 138,385	\$ 67,102	\$ 103,304	\$ 99,741	\$ 142,541	\$ 18,168	\$ 569,241	\$ 144,721	\$ 37,511	\$ 751,473
Future production costs	(42,817)	(30,899)	(26,992)	(34,359)	(12,744)	(10,814)	(158,625)	(30,015)	(17,061)	(205,701)
Future development costs	(13,616)	(8,283)	(9,486)	(12,629)	(15,681)	(3,031)	(62,726)	(19,349)	(4,454)	(86,529)
Future income taxes	(27,129)	(8,445)	(47,884)	(24,225)	(34,235)	(2,692)	(144,610)	(28,607)	(6,634)	(179,851)
Undiscounted future net cash flows	54,823	19,475	18,942	28,528	79,881	1,631	203,280	66,750	9,362	279,392
10 percent midyear annual discount for timing of estimated cash flows	(23,257)	(12,082)	(6,145)	(8,570)	(43,325)	(380)	(93,759)	(34,987)	(5,294)	(134,040)
Standardized Measure Net Cash Flows	\$ 31,566	\$ 7,393	\$ 12,797	\$ 19,958	\$ 36,556	\$ 1,251	\$ 109,521	\$ 31,763	\$ 4,068	\$ 145,352
At December 31, 2013¹										
Future cash inflows from production	\$ 136,942	\$ 73,468	\$ 117,119	\$ 111,970	\$ 130,620	\$ 20,232	\$ 590,351	\$ 157,108	\$ 43,380	\$ 790,839
Future production costs	(39,009)	(29,373)	(27,800)	(35,716)	(12,593)	(10,099)	(154,590)	(32,245)	(18,027)	(204,862)
Future development costs	(12,058)	(10,149)	(10,983)	(17,290)	(18,220)	(2,644)	(71,344)	(12,852)	(3,879)	(88,075)
Future income taxes	(28,458)	(9,454)	(53,953)	(26,162)	(29,942)	(4,727)	(152,696)	(33,603)	(9,418)	(195,717)
Undiscounted future net cash flows	57,417	24,492	24,383	32,802	69,865	2,762	211,721	78,408	12,056	302,185
10 percent midyear annual discount for timing of estimated cash flows	(23,055)	(15,217)	(8,165)	(10,901)	(39,117)	(888)	(97,343)	(41,444)	(6,482)	(145,269)
Standardized Measure Net Cash Flows	\$ 34,362	\$ 9,275	\$ 16,218	\$ 21,901	\$ 30,748	\$ 1,874	\$ 114,378	\$ 36,964	\$ 5,574	\$ 156,916
At December 31, 2012¹										
Future cash inflows from production	\$ 139,856	\$ 72,548	\$ 122,189	\$ 121,849	\$ 134,009	\$ 19,653	\$ 610,104	\$ 169,966	\$ 47,496	\$ 827,566
Future production costs	(41,773)	(27,191)	(24,592)	(35,713)	(15,649)	(8,768)	(153,686)	(32,085)	(19,899)	(205,670)
Future development costs	(11,192)	(14,810)	(14,601)	(17,275)	(24,923)	(1,946)	(84,747)	(12,355)	(3,710)	(100,812)
Future income taxes	(32,357)	(9,902)	(48,683)	(30,763)	(28,031)	(5,589)	(155,325)	(37,658)	(13,363)	(206,346)
Undiscounted future net cash flows	54,534	20,645	34,313	38,098	65,406	3,350	216,346	87,868	10,524	314,738
10 percent midyear annual discount for timing of estimated cash flows	(23,055)	(14,331)	(12,429)	(13,033)	(42,012)	(860)	(105,720)	(47,534)	(5,644)	(158,898)
Standardized Measure Net Cash Flows	\$ 31,479	\$ 6,314	\$ 21,884	\$ 25,065	\$ 23,394	\$ 2,490	\$ 110,626	\$ 40,334	\$ 4,880	\$ 155,840

¹ 2012 and 2013 conformed to 2014 presentation.

Table VII - Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves

The changes in present values between years, which can be significant, reflect changes in estimated proved-reserve quantities and prices and assumptions used in forecasting production volumes and costs. Changes in the timing of production are included with “Revisions of previous quantity estimates.”

<i>Millions of dollars</i>	Consolidated Companies ¹	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2012	\$ 106,948	\$ 45,891	\$ 152,839
Sales and transfers of oil and gas produced net of production costs	(49,094)	(7,708)	(56,802)
Development costs incurred	18,013	942	18,955
Purchases of reserves	376	—	376
Sales of reserves	(1,665)	—	(1,665)
Extensions, discoveries and improved recovery less related costs	9,296	106	9,402
Revisions of previous quantity estimates	26,060	3,759	29,819
Net changes in prices, development and production costs	(18,752)	(2,266)	(21,018)
Accretion of discount	18,026	6,322	24,348
Net change in income tax	1,418	(1,832)	(414)
Net change for 2012	3,678	(677)	3,001
Present Value at December 31, 2012	\$ 110,626	\$ 45,214	\$ 155,840
Sales and transfers of oil and gas produced net of production costs	(43,760)	(8,692)	(52,452)
Development costs incurred	22,907	1,411	24,318
Purchases of reserves	184	—	184
Sales of reserves	243	—	243
Extensions, discoveries and improved recovery less related costs	3,135	—	3,135
Revisions of previous quantity estimates	22,796	1,306	24,102
Net changes in prices, development and production costs	(22,591)	(5,925)	(28,516)
Accretion of discount	18,510	6,406	24,916
Net change in income tax	2,328	2,818	5,146
Net change for 2013	3,752	(2,676)	1,076
Present Value at December 31, 2013	\$ 114,378	\$ 42,538	\$ 156,916
Sales and transfers of oil and gas produced net of production costs	(38,935)	(7,578)	(46,513)
Development costs incurred	25,687	1,963	27,650
Purchases of reserves	255	—	255
Sales of reserves	(1,178)	—	(1,178)
Extensions, discoveries and improved recovery less related costs	3,956	215	4,171
Revisions of previous quantity estimates	17,462	1,573	19,035
Net changes in prices, development and production costs	(34,953)	(12,496)	(47,449)
Accretion of discount	18,884	5,926	24,810
Net change in income tax	3,965	3,690	7,655
Net change for 2014	(4,857)	(6,707)	(11,564)
Present Value at December 31, 2014	\$ 109,521	\$ 35,831	\$ 145,352

¹ 2012 and 2013 conformed to 2014 presentation.

Chevron History

1879

Incorporated in San Francisco, California, as the Pacific Coast Oil Company.

1900

Acquired by the West Coast operations of John D. Rockefeller's original Standard Oil Company.

1911

Emerged as an autonomous entity – Standard Oil Company (California) – following U.S. Supreme Court decision to divide the Standard Oil conglomerate into 34 independent companies.

1926

Acquired Pacific Oil Company to become Standard Oil Company of California (Socal).

1936

Formed the Caltex Group of Companies, jointly owned by Socal and The Texas Company (later became Texaco), to combine Socal's exploration and production interests in the Middle East and Indonesia and provide an outlet for crude oil through The Texas Company's marketing network in Africa and Asia.

1947

Acquired Signal Oil Company, obtaining the Signal brand name and adding 2,000 retail stations in the western United States.

1961

Acquired Standard Oil Company (Kentucky), a major petroleum products marketer in five southeastern states, to provide outlets for crude oil from southern Louisiana and the U.S. Gulf of Mexico, where the company was a major producer.

1984

Acquired Gulf Corporation – nearly doubling the company's crude oil and natural gas activities – and gained significant presence in industrial chemicals, natural gas liquids and coal. Changed name to Chevron Corporation to identify with the name under which most products were marketed.

1988

Purchased Tenneco Inc.'s U.S. Gulf of Mexico crude oil and natural gas properties, becoming one of the largest U.S. natural gas producers.

1993

Formed Tengizchevroil, a joint venture with the Republic of Kazakhstan, to develop and produce the giant Tengiz Field, becoming the first major Western oil company to enter newly independent Kazakhstan.

1999

Acquired Rutherford-Moran Oil Corporation. This acquisition provided inroads to Asian natural gas markets.

2001

Merged with Texaco Inc. and changed name to ChevronTexaco Corporation. Became the second-largest U.S.-based energy company.

2002

Relocated corporate headquarters from San Francisco, California, to San Ramon, California.

2005

Acquired Unocal Corporation, an independent crude oil and natural gas exploration and production company. Unocal's upstream assets bolstered Chevron's already-strong position in the Asia-Pacific, U.S. Gulf of Mexico and Caspian regions. Changed name to Chevron Corporation to convey a clearer, stronger and more unified presence in the global marketplace.

2011

Acquired Atlas Energy, Inc., an independent U.S. developer and producer of shale gas resources. The acquired assets provide a targeted, high-quality core acreage position primarily in the Marcellus Shale.

Board of Directors



John S. Watson, 58

Chairman of the Board and Chief Executive Officer since 2010. Previously he was elected a Director and Vice Chairman in 2009; Executive Vice President, Strategy and Development; Corporate Vice President and President, Chevron International Exploration and Production Company; Vice President and Chief Financial Officer; and Corporate Vice President, Strategic Planning. He serves on the Board of Directors and the Executive Committee of the American Petroleum Institute. Joined Chevron in 1980.

George L. Kirkland, 64

Vice Chairman of the Board since 2010 and **Executive Vice President, Upstream**, since 2005. In addition to Board responsibilities, he is responsible for global exploration and production activities for crude oil and natural gas and its technology and enterprise support functions. Previously Corporate Vice President and President, Chevron Overseas Petroleum Inc., and President, Chevron U.S.A. Production Company. Joined Chevron in 1974.

Alexander B. Cummings Jr., 58

Director since 2014. He is Executive Vice President and Chief Administrative Officer of The Coca-Cola Company, the world's largest beverage manufacturer. Previously he was President and Chief Operating Officer of the company's Africa Group. He is a Director of Coca-Cola Bottling Co. Consolidated. (1)

Linnet F. Deily, 69

Director since 2006. She served as a Deputy U.S. Trade Representative and U.S. Ambassador to the World Trade Organization. Previously she was Vice Chairman of Charles Schwab Corporation. She is a Director of Honeywell International Inc. (2, 3)

Robert E. Denham, 69

Lead Director since 2011 and a **Director** since 2004. He is a Partner in the law firm of Munger, Tolles & Olson LLP. Previously he was Chairman and Chief Executive Officer of Salomon Inc. He is a Director of The New York Times Company; Oaktree Capital Group, LLC; and Fomento Económico Mexicano, S.A. de C.V. (3, 4)

Alice P. Gast, 56

Director since 2012. She is President of Imperial College London, a public research university specializing in science, engineering, medicine and business. Previously she was President of Lehigh University in Pennsylvania. Prior to that she was Vice President for Research, Associate Provost and Robert T. Haslam Chair in Chemical Engineering at the Massachusetts Institute of Technology. (1)

Enrique Hernandez Jr., 59

Director since 2008. He is Chairman, Chief Executive Officer and President of Inter-Con Security Systems, Inc., a global provider of physical and facility security support services to local, state, federal and foreign governments, utilities, and major corporations. He is a Director of McDonald's Corporation; Nordstrom, Inc.; and Wells Fargo & Company. (2, 4)



Jon M. Huntsman Jr., 55

Director since 2014. He is Chairman of the Board of the Atlantic Council, a nonprofit organization that promotes leadership and engagement in international affairs, and Chairman of the Board of the Huntsman Cancer Foundation, a nonprofit organization that financially supports research, education and patient care initiatives at the Huntsman Cancer Institute at the University of Utah. In 2011 he was a candidate for the Republican nomination for President of the United States. Previously he served as U.S. Ambassador to China and was Governor of Utah for two consecutive terms. He is a Director of Caterpillar Inc., Ford Motor Company and Huntsman Corporation. (2, 3)

Charles W. Moorman, 63

Director since 2012. He is Chairman of the Board and Chief Executive Officer of Norfolk Southern Corporation, a freight transportation company. Previously he served as President at Norfolk Southern from 2004 to 2013. (1)

Kevin W. Sharer, 67

Director since 2007. He is a Senior Lecturer of Business Administration at the Harvard Business School and is retired Chairman of the Board and Chief Executive Officer of Amgen Inc., a global biotechnology medicines company. Previously he was President and Chief Operating Officer of Amgen. He is a Director of Northrop Grumman Corporation. (1)

John G. Stumpf, 61

Director since 2010. He is Chairman of the Board, Chief Executive Officer and President of Wells Fargo & Company, a nationwide, diversified, community-based financial services company. Previously he served as Group Executive Vice President of Community Banking at Wells Fargo. He is a Director of Target Corporation. (1)

Ronald D. Sugar, 66

Director since 2005. He is a Senior Advisor to various businesses and organizations, including Ares Management LLC, a leading private investment firm; Bain & Company, a global consulting firm; Temasek Americas Advisory Panel, Singapore's sovereign wealth fund; and the G100 Network and the World 50, peer-to-peer exchanges for current and former senior executives from some of the world's largest companies. He is retired Chairman of the Board and Chief Executive Officer of Northrop Grumman Corporation. He is a Director of Amgen Inc., Air Lease Corporation and Apple Inc. (1)

Inge G. Thulin, 61

Director since January 2015. He is Chairman of the Board, President and Chief Executive Office of the 3M Company, a diversified technology company. Previously he was Executive Vice President and Chief Operating Officer of 3M. Prior to that he was the company's Executive Vice President of International Operations. (3, 4)

Carl Ware, 71

Director since 2001. He is a retired Executive Vice President of The Coca-Cola Company, the world's largest beverage manufacturer. Previously he was a Senior Adviser to the Chief Executive Officer of The Coca-Cola Company and Executive Vice President, Global Public Affairs and Administration, for The Coca-Cola Company. (2, 4)

Committees of the Board

- 1) Audit: Ronald D. Sugar, Chair
- 2) Public Policy: Linnet F. Deily, Chair
- 3) Board Nominating and Governance: Robert E. Denham, Chair
- 4) Management Compensation: Carl Ware, Chair

Corporate Officers



Lydia I. Beebe, 62

Corporate Secretary and Chief Governance Officer since 1995. Responsible for providing advice and counsel to the Board of Directors and senior management on corporate governance matters and managing the Corporate Governance function. Previously Senior Manager, Chevron Tax Department. Joined Chevron in 1977.

Paul V. Bennett, 61

Vice President and Treasurer since 2011. Responsible for banking, financing, cash management, insurance, pension investments, and credit and receivables activities corporatewide. Previously Vice President, Finance, Downstream and Chemicals. Joined the company in 1980.

Pierre R. Breber, 50

Corporate Vice President and President, Chevron Gas and Midstream, since 2014. Responsible for commercializing the company's natural gas resources, supporting the development of new growth opportunities worldwide, and overseeing shipping, pipeline, power, energy efficiency, and supply and trading operations. Previously Managing Director, Asia South Business Unit. Joined the company in 1989.

Joseph C. Geagea, 55

Senior Vice President, Technology, Projects and Services, since 2014. Responsible for energy technology; delivery of major capital projects; procurement; information technology; health, environment and safety; upstream production services; and talent selection and development in support of Chevron's upstream, downstream and midstream businesses. Previously Corporate Vice President and President, Chevron Gas and Midstream. Joined the company in 1982.

Stephen W. Green, 57

Vice President, Policy, Government and Public Affairs, since 2011. Responsible for U.S. and international government relations, all aspects of communications, and the company's worldwide efforts to protect and enhance its reputation. Previously President, Chevron Indonesia Company and Managing Director, IndoAsia Business Unit, Chevron Asia Pacific Exploration and Production Company. Joined the company in 2005 upon the merger with Unocal Corporation.

James W. Johnson, 56

Senior Vice President, Upstream, since 2014. Responsible for Chevron's global exploration and production activities for crude oil and natural gas. Previously President, Chevron Europe, Eurasia and Middle East Exploration and Production Company; Managing Director, Eurasia Business Unit; and Managing Director, Australasia Business Unit. Joined the company in 1981.

Joe W. Laymon, 62

Vice President, Human Resources and Corporate Services, since 2008. Responsible for human resources, medical services, security, aviation, diversity and ombuds. Previously Group Vice President, Corporate Human Resources and Labor Affairs, Ford Motor Company. Joined the company in 2008.

Wesley E. Lohec, 55

Vice President, Health, Environment and Safety (HES), since 2011. Responsible for HES strategic planning and issues management, compliance assurance, emergency response, and Chevron's Environmental Management Company. Previously Managing Director, Latin America, Chevron Africa and Latin America Exploration and Production Company. Joined the company in 1981.



Charles N. Macfarlane, 60

Vice President since 2013 and **General Tax Counsel** since 2010. Responsible for directing Chevron's worldwide tax activities. Previously the company's Assistant General Tax Counsel. Joined Chevron in 1984 upon the merger with Gulf Oil Corporation.

Joseph M. Naylor, 54

Vice President, Strategic Planning, since 2013. Responsible for advising senior corporate executives in setting strategic direction for the company, allocating capital and other resources, and determining operating unit performance measures and targets. Previously General Manager, Upstream Strategy and Planning. Joined Chevron in 1982.

Jeanette L. Ourada, 49

Vice President and Comptroller since April 2015. Responsible for corporatewide accounting, financial reporting and analysis, internal controls, and Finance Shared Services. Previously General Manager, Finance Shared Services. Joined Chevron in 2005 upon the merger with Unocal Corporation.

R. Hewitt Pate, 52

Vice President and General Counsel since 2009. Responsible for directing the company's worldwide legal affairs. Previously Chair, Competition Practice, Hunton & Williams LLP, Washington, D.C., and Assistant Attorney General, Antitrust Division, U.S. Department of Justice. Joined Chevron in 2009.

Jay R. Pryor, 57

Vice President, Business Development, since 2006. Responsible for identifying and developing new, large-scale upstream and downstream business opportunities, including mergers and acquisitions. Previously Managing Director, Chevron Nigeria Ltd., and Managing Director, Asia South Business Unit and Chevron Offshore (Thailand) Ltd. Joined Chevron in 1979.

Michael K. Wirth, 54

Executive Vice President, Downstream and Chemicals, since 2006. Responsible for worldwide manufacturing, marketing, lubricants, chemicals and Oronite additives. Previously President, Global Supply and Trading, and President, Marketing, Asia/Middle East/Africa Strategic Business Unit. Joined Chevron in 1982.

Patricia E. Yarrington, 59

Vice President and Chief Financial Officer since 2009. Responsible for comptroller, tax, treasury, audit and investor relations activities. Served as Chairman of the San Francisco Federal Reserve's Board of Directors in 2013 and 2014. Previously Corporate Vice President and Treasurer; Corporate Vice President, Policy, Government and Public Affairs; Corporate Vice President, Strategic Planning; and President, Chevron Canada Limited. Joined Chevron in 1980.

Executive Committee

John S. Watson, George L. Kirkland, Pierre R. Breber, Joseph C. Geagea, James W. Johnson, R. Hewitt Pate, Michael K. Wirth and Patricia E. Yarrington. Lydia I. Beebe, Secretary.

Stockholder and Investor Information

Stock Exchange Listing

Chevron common stock is listed on the New York Stock Exchange. The symbol is "CVX."

Stockholder Information

Questions about stock ownership, changes of address, dividend payments or direct deposit of dividends should be directed to Chevron's transfer agent and registrar:

Computershare
P.O. Box 30170
College Station, TX 77842-3170
800 368 8357
www.computershare.com/investor

Overnight correspondence should be sent to:

Computershare
211 Quality Circle, Suite 210
College Station, TX 77845-4470

The Computershare Investment Plan features dividend reinvestment, optional cash investments of \$50 to \$100,000 a year and automatic stock purchase.

Dividend Payment Dates

Quarterly dividends on common stock are paid, following declaration by the Board of Directors, on or about the 10th day of March, June, September and December. Direct deposit of dividends is available to stockholders. For information, contact Computershare. (See *Stockholder Information*.)

Annual Meeting

The Annual Meeting of stockholders will be held at 8:00 a.m. PDT, Wednesday, May 27, 2015, at: Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324

Electronic Access

In an effort to conserve natural resources and reduce the cost of printing and shipping proxy materials next year, we encourage stockholders to register to receive these documents via email and vote their shares on the Internet. Stockholders of record may sign up on our website, www.icsdelivery.com/cvx/index.html, for electronic access. Enrollment is revocable until each year's Annual Meeting record date. Beneficial stockholders may be able to request electronic access by contacting their broker or bank, or Broadridge Financial Solutions at: www.icsdelivery.com/cvx/index.html.

Investor Information

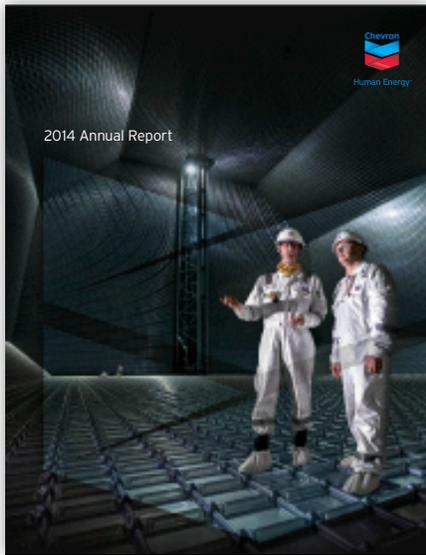
Securities analysts, portfolio managers and representatives of financial institutions may contact: Investor Relations
Chevron Corporation
6001 Bollinger Canyon Road, A3064
San Ramon, CA 94583-2324
925 842 5690
Email: invest@chevron.com

Notice

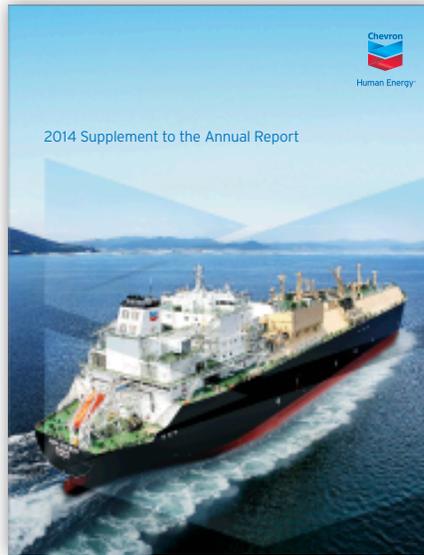
As used in this report, the term "Chevron" and such terms as "the company," "the corporation," "our," "we" and "us" may refer to one or more of its consolidated subsidiaries or to all of them taken as a whole. All of these terms are used for convenience only and are not intended as a precise description of any of the separate companies, each of which manages its own affairs.

Corporate Headquarters

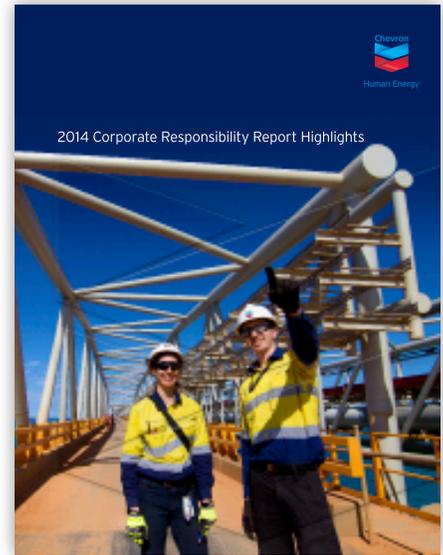
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324
925 842 1000



2014 Annual Report



2014 Supplement to the Annual Report



2014 Corporate Responsibility Report

Publications and Other News Sources

The *Annual Report*, distributed in April, summarizes the company's financial performance in the preceding year and provides an overview of the company's major activities.

Chevron's Annual Report on Form 10-K filed with the U.S. Securities and Exchange Commission and the *Supplement to the Annual Report*, containing additional financial and operating data, are available on the company's website, Chevron.com, or copies may be requested by writing to:

Comptroller's Department
Chevron Corporation
6001 Bollinger Canyon Road, A3201
San Ramon, CA 94583-2324

The *Corporate Responsibility Report* is available in May on the company's website, Chevron.com/CR, or a copy may be requested by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6101 Bollinger Canyon Road
BR1X3208
San Ramon, CA 94583-5177

Additional information about the company's corporate responsibility efforts can be found on Chevron's websites, Chevron.com/CR or Chevron.com/Community.

Details of the company's *political contributions* for 2014 are available on the company's website, Chevron.com, or by writing to:
Policy, Government and Public Affairs
Chevron Corporation
6101 Bollinger Canyon Road
BR1X3432
San Ramon, CA 94583-5177

For additional information about the company and the energy industry, visit Chevron's website, Chevron.com. It includes articles, news releases, speeches, quarterly earnings information, the *Proxy Statement* and the complete text of this *Annual Report*.

This *Annual Report* contains forward-looking statements – identified by words such as "expects," "intends," "projects," etc. – that reflect management's current estimates and beliefs, but are not guarantees of future results. Please see "Cautionary Statement Relevant to Forward-Looking Information for the Purpose of 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995" on Page 9 for a discussion of some of the factors that could cause actual results to differ materially.

PHOTOGRAPHY

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