



Human Energy®

2013 Annual Report



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On the cover: In mid-November 2013 the floating production unit for the Jack/St. Malo development began its journey from the fabrication yard in Ingleside, Texas, to its mooring location in the Walker Ridge area of the deepwater U.S. Gulf of Mexico. Installation was completed, and first oil is expected in late 2014.

This page: The Angola liquefied natural gas (LNG) plant, located in Soyo, made its first shipment in the second quarter of 2013. It is the world's first LNG plant supplied by natural gas that is a byproduct of crude oil production. Angola LNG is one of the largest energy projects on the African continent.



Momentum continues to build as Chevron undertakes some of the world's largest and most complex energy projects. We expect the company's upstream projects to grow our crude oil and natural gas production into the next decade. At the same time, our downstream projects are focused on delivering competitive returns and targeted growth. The long-term investments we are making will contribute to the world's need for reliable and affordable energy and will help ensure that we deliver sustained value to our stockholders, employees, business partners and the communities where we operate.

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/AnnualReport2013.



To Our Stockholders

Chevron delivered solid financial and operating results in 2013 while advancing our industry-leading queue of major capital projects. Our sound financial performance was reflected in net income of \$21.4 billion on sales and other operating revenues of \$220 billion. We achieved a competitive 13.5 percent return on capital employed. And for the 26th consecutive year, we increased our annual dividend payout to stockholders. Our total stockholder returns of just under 15 percent over the past five- and 10-year periods continue to lead our peer group.



Throughout 2013 our major businesses generated strong operating results. In the upstream, we ranked No.1 in earnings per barrel relative to our peers for the fourth continuous year. We began production at the Angola liquefied natural gas (LNG) plant and achieved first oil from the Papa-Terra project offshore Brazil. In 2013 we also advanced our two world-class LNG projects in Western Australia. Construction at Gorgon is approximately 75 percent complete, and construction at Wheatstone is approximately 25 percent complete. Over the next four years we anticipate 15 project startups with a Chevron investment of more than \$1 billion each, including two key deepwater projects in the U.S. Gulf of Mexico – Jack/St. Malo and Big Foot, which are expected to come online in 2014 and 2015, respectively.

We continued to add resources to our portfolio through both exploration and targeted acquisitions in 2013. The success rate of our exploration wells was nearly 59 percent, and we added crude oil and natural gas resources through discoveries in 10 countries. We grew our portfolio of opportunities with a new operating interest in the Kurdistan Region of Iraq, new acreage in the Bight Basin offshore South Australia, and finalized agreements to pursue unconventional resources in Argentina as well as assume full operatorship of the Kitimat LNG plant and Pacific Trail Pipeline in Canada. We also successfully completed the first phase of our Duvernay Shale program in Canada. We added approximately 800 million barrels of net oil-equivalent proved reserves, replacing almost 85 percent of production in 2013. The company's three-year average reserve replacement ratio is 123 percent of net oil-equivalent production.

In downstream and chemicals, we continued to benefit from the investments we have made in our refining system and from our competitive position in additives, petrochemicals and lubricants. In 2013 we ranked No. 2 in earnings per barrel relative to our peer group. And we neared completion on the construction of our Pascagoula Base Oil Plant, which will position us as the world's leading supplier of premium base oil when it starts up in 2014. We also reached final investment decision on Chevron Phillips Chemical Company's (CPChem) U.S. Gulf Coast ethylene cracker and derivatives unit. These projects allow CPChem to take advantage of the growth in U.S. shale gas and associated ethane.

Despite statistically strong safety performance, we are not yet incident-free. In 2013 we undertook extensive actions to enhance process safety to prevent serious incidents. Chevron is deeply committed to our goal of zero incidents and achieving world-class performance in all measures of safety.

Meeting the world's long-term demand for energy requires significant investment. We enter 2014 with a capital and exploratory budget of \$39.8 billion. This reflects the company's confidence in our unparalleled queue of projects that will help us deliver valuable growth. Chevron's capital investments enable us to grow our production while continuing to deliver industry-leading

and invest in programs to create measurable and lasting value. Our business and social investments boost local economies by creating jobs, improving livelihoods and supporting local businesses. Beyond direct business investment and taxes, over the past eight years we contributed almost \$1.5 billion to local communities through social investments that foster economic growth, with a significant focus on health, education and economic development programs. You can find more information in our 2013 *Corporate Responsibility Report*.

The men and women of Chevron are committed to our vision of being *the* global energy company most admired for its people, partnership and performance. We remain focused on finding and producing the affordable, reliable energy that drives global economic growth and human prosperity. And due to our unparalleled project portfolio and proven business strategies, I am confident that we are strongly positioned to contribute to these aspirations, as well as create enduring value for our stockholders.

Overall, our long-term production growth outlook is compelling, and we are investing today in projects that will deliver production, cash flow and earnings growth to the end of the decade.

Delivering results the right way is a responsibility that our company takes seriously. Our Operational Excellence Management System guides us as we seek to achieve increasingly higher levels of safety, operational and environmental performance. This focus helped us deliver our lowest number on record of serious process safety-related loss-of-containment events and liquid spills. In 2013 we continued to be a leader in personal safety as measured by injuries requiring time away from work.

performance. We anticipate that 2014 will be the peak year for spending on our Australian LNG projects as we move them closer to first production. Overall, our long-term production growth outlook is compelling, and we are investing today in projects that will deliver production, cash flow and earnings growth to the end of the decade.

Chevron's business success is deeply linked to society's progress. We partner with governments, nongovernmental organizations and communities to build beneficial and enduring relationships, manage the impacts of our operations,

Thank you for investing in Chevron.



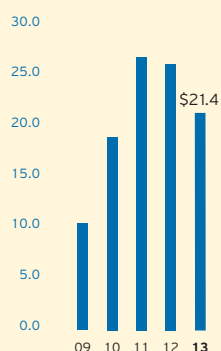
John S. Watson
Chairman of the Board and
Chief Executive Officer
February 21, 2014

Chevron Financial Highlights

Millions of dollars, except per-share amounts	2013	2012	% Change
Net income attributable to Chevron Corporation	\$ 21,423	\$ 26,179	(18.2)%
Sales and other operating revenues	\$ 220,156	\$ 230,590	(4.5)%
Noncontrolling interests income	\$ 174	\$ 157	10.8 %
Interest expense (after tax)	\$ –	\$ –	0.0 %
Capital and exploratory expenditures*	\$ 41,877	\$ 34,229	22.3 %
Total assets at year-end	\$ 253,753	\$ 232,982	8.9 %
Total debt and capital lease obligations at year-end	\$ 20,431	\$ 12,192	67.6 %
Noncontrolling interests	\$ 1,314	\$ 1,308	0.5 %
Chevron Corporation stockholders' equity at year-end	\$ 149,113	\$ 136,524	9.2 %
Cash provided by operating activities	\$ 35,002	\$ 38,812	(9.8)%
Common shares outstanding at year-end (Thousands)	1,899,435	1,932,530	(1.7)%
Per-share data			
Net income attributable to Chevron Corporation – diluted	\$ 11.09	\$ 13.32	(16.7)%
Cash dividends	\$ 3.90	\$ 3.51	11.1 %
Chevron Corporation stockholders' equity	\$ 78.50	\$ 70.65	11.1 %
Common stock price at year-end	\$ 124.91	\$ 108.14	15.5 %
Total debt to total debt-plus-equity ratio	12.1%	8.2%	
Return on average Chevron Corporation stockholders' equity	15.0%	20.3%	
Return on capital employed (ROCE)	13.5%	18.7%	

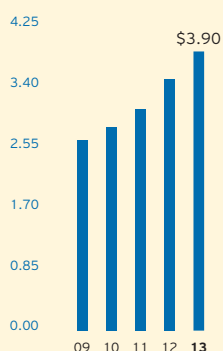
*Includes equity in affiliates

Net Income Attributable to Chevron Corporation
Billions of dollars



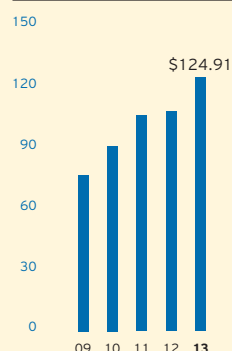
The decrease in 2013 was due to lower earnings in upstream and downstream as a result of lower gains on asset sales, higher operating expenses, lower margins on refined product sales, and lower crude oil production.

Annual Cash Dividends
Dollars per share



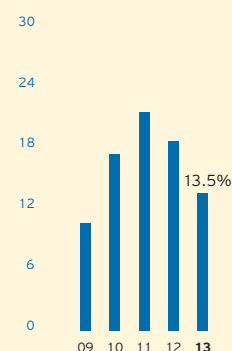
The company's annual dividend increased for the 26th consecutive year.

Chevron Year-End Common Stock Price
Dollars per share



The company's stock price rose 15.5 percent in 2013.

Return on Capital Employed
Percent



Chevron's return on capital employed declined to 13.5 percent on lower earnings and higher capital employed.

Chevron Operating Highlights¹

	2013	2012	% Change
Net production of crude oil, condensate and natural gas liquids (Thousands of barrels per day)	1,731	1,764	(1.9) %
Net production of natural gas (Millions of cubic feet per day)	5,192	5,074	2.3 %
Total net oil-equivalent production (Thousands of oil-equivalent barrels per day)	2,597	2,610	(0.5) %
Refinery input (Thousands of barrels per day)	1,638	1,702	(3.8) %
Sales of refined products (Thousands of barrels per day)	2,711	2,765	(2.0) %
Net proved reserves of crude oil, condensate and natural gas liquids ² (Millions of barrels)			
– Consolidated companies	4,303	4,353	(1.1) %
– Affiliated companies	2,042	2,128	(4.0) %
Net proved reserves of natural gas ² (Billions of cubic feet)			
– Consolidated companies	25,670	25,654	0.1 %
– Affiliated companies	3,476	3,541	(1.8) %
Net proved oil-equivalent reserves ² (Millions of barrels)			
– Consolidated companies	8,582	8,629	(0.5) %
– Affiliated companies	2,621	2,718	(3.6) %
Number of employees at year-end ³	61,345	58,286	5.2 %

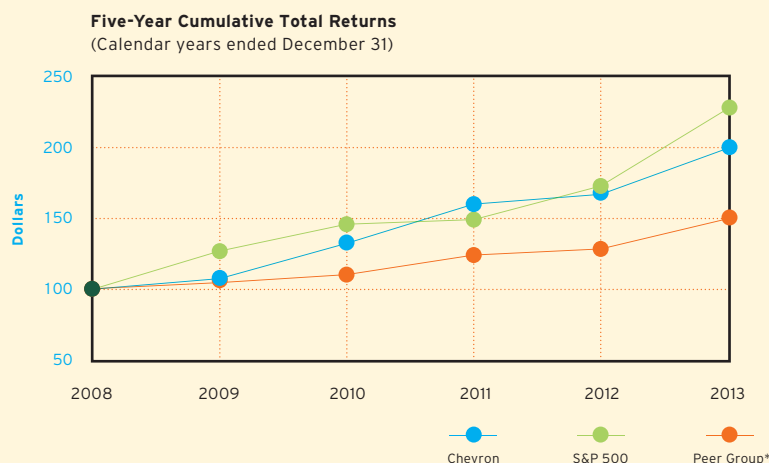
¹ Includes equity in affiliates, except number of employees

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, 2008, and ending December 31, 2013, 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, 2008, as of the end of each year between 2009 and 2013.



	2008	2009	2010	2011	2012	2013
Chevron	100	108.10	132.84	159.77	167.75	200.03
S&P 500	100	126.45	145.48	148.56	172.31	228.15
Peer Group*	100	107.14	109.91	123.75	128.06	150.16

*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 get 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; provide renewable energy and energy efficiency solutions; and develop the energy resources of the future, including conducting advanced biofuels research.



Photo: A work crew discusses the day's upcoming activities at the Wolfcamp tight oil play in the Midland Basin, which is part of the liquids-rich Permian Basin of West Texas and southeast New Mexico.

Upstream	Strategy: Grow profitably in core areas and build new legacy positions.	Upstream explores for and produces crude oil and natural gas. At the end of 2013 worldwide net oil-equivalent proved reserves for consolidated and affiliated companies were 11.2 billion barrels. In 2013 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 U.S. deep-water Gulf of Mexico and the offshore areas of Australia and western Africa, the Kurdistan Region of Iraq, and frontier settings in Liberia, Morocco, Sierra Leone, Suriname and the Bight Basin of Australia. Exploration areas for shale and tight resources include Argentina, Australia, Canada, China, Lithuania, Poland, Romania, Ukraine and the United States.
Downstream and Chemicals	Strategy: Deliver competitive returns and grow earnings across the value chain.	Downstream and Chemicals includes refining, fuels and lubricants marketing, and petrochemicals and additives manufacturing and marketing. In 2013 we processed 1.6 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 operations are the west coast of North America, the U.S. Gulf Coast, Singapore, Thailand, South Korea, Australia and South Africa. We hold interests in 14 fuel refineries and market transportation fuels and lubricants under the Chevron, Texaco and Caltex brands. Products are sold through a network of 16,634 retail stations, including those of affiliated companies. Our chemical 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.
Gas and Midstream	Strategy: Apply commercial and functional excellence to enable the success of Upstream and Downstream and Chemicals.	Gas and Midstream links Upstream and Downstream and Chemicals to the market and is responsible for providing safe and reliable midstream infrastructure and services. 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.
Technology	Strategy: Differentiate performance through technology.	Our three technology companies – Energy Technology, Technology Ventures and Information Technology – are focused on driving business value in every aspect of our operations. We operate technology centers in Australia, the United Kingdom and the United States. Together they provide strategic research, technology development, and technical and computing infrastructure services to our global businesses.
Renewable Energy and Energy Efficiency	Strategy: Invest in profitable renewable energy and energy efficiency solutions.	We are one of the world's leading producers of geothermal energy, with operations in Indonesia and the Philippines. We are involved in developing promising renewable sources of energy, including solar and advanced biofuels from nonfood sources. We continually improve the energy efficiency of our operations worldwide, as well as provide solutions that help make our customers in the United States more energy efficient.
Operational Excellence		We define operational excellence as the systematic management of process safety, personal safety and health, environment, reliability, and efficiency. Safety is our highest priority. We are committed to attaining world-class performance in operational excellence and believe our goal of zero safety and operating incidents is attainable.

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 fields.

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.

Price effects on entitlement volumes The impact on Chevron's share of net production and net proved reserves due to changes in crude oil and natural gas prices between periods. Under production-sharing and variable-royalty provisions of certain agreements, price 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 production-sharing contracts.

Production *Total production* refers to all the crude oil (including *synthetic oil*), natural gas liquids 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, natural gas liquids 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, 2013.

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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Five-Year Financial Summary

Five-Year Operating Summary

Supplemental Information on Oil and Gas Producing Activities

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," "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 chemical 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 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; 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>	2013	2012	2011
Net Income Attributable to			
Chevron Corporation	\$ 21,423	\$ 26,179	\$ 26,895
Per Share Amounts:			
Net Income Attributable to			
Chevron Corporation			
– Basic	\$ 11.18	\$ 13.42	\$ 13.54
– Diluted	\$ 11.09	\$ 13.32	\$ 13.44
Dividends	\$ 3.90	\$ 3.51	\$ 3.09
Sales and Other			
Operating Revenues	\$ 220,156	\$ 230,590	\$ 244,371
Return on:			
Capital Employed	13.5%	18.7%	21.6%
Stockholders' Equity	15.0%	20.3%	23.8%

Earnings by Major Operating Area

<i>Millions of dollars</i>	2013	2012	2011
Upstream			
United States	\$ 4,044	\$ 5,332	\$ 6,512
International	16,765	18,456	18,274
Total Upstream	20,809	23,788	24,786
Downstream			
United States	787	2,048	1,506
International	1,450	2,251	2,085
Total Downstream	2,237	4,299	3,591
All Other	(1,623)	(1,908)	(1,482)
Net Income Attributable to			
Chevron Corporation ^{1,2}	\$ 21,423	\$ 26,179	\$ 26,895

¹ Includes foreign currency effects: \$ 474 \$ (454) \$ 121

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 14 for a discussion of financial results by major operating area for the three years ended December 31, 2013.

Business Environment and Outlook

Chevron is a global energy company with substantial business activities in the following countries: Angola, Argentina, Australia, Azerbaijan, Bangladesh, Brazil, Cambodia, Canada, Chad, China, Colombia, Democratic Republic of the Congo, Denmark, Indonesia, Kazakhstan, Myanmar, the Netherlands, Nigeria, Norway, 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 and downstream business segments. The biggest factor affecting the results of operations for the company is the price of crude oil. In the downstream business, crude oil is the largest cost component of refined products. Seasonality is not a primary driver of changes in the company's quarterly earnings during the year.

To sustain its long-term competitive position in the upstream business, the company must develop and replenish an inventory of projects that offer attractive financial returns for the investment required. Identifying promising areas for exploration, acquiring the necessary rights to explore for and to produce crude oil and natural gas, drilling successfully, and handling the many technical and operational details in a safe and cost-effective manner are all important factors in this effort. Projects often require long lead times and large capital commitments.

The company's operations, especially upstream, can also be affected by changing economic, regulatory and political environments in the various countries in which it operates, including the United States. From time to time, certain governments have sought to renegotiate contracts or impose additional costs on the company. Governments may attempt to do so in the future. Civil unrest, acts of violence or strained relations between a government and the company or other governments may impact the company's operations or investments. Those developments have at times significantly affected the company's operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries.

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 14 for discussions of net gains on asset sales during 2013. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

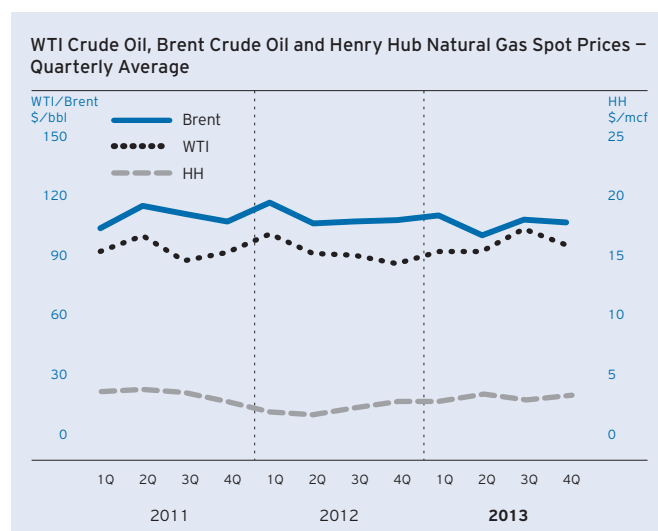
The company closely monitors developments in the financial and credit markets, the level of worldwide economic activity, and the implications for the company of movements in prices for crude oil and natural gas. Management takes these developments into account in the conduct of daily operations and for 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 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. External factors include not only the general level of inflation, but also 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. Capital and exploratory expenditures and operating expenses can also be affected by damage to production facilities caused by severe weather or civil unrest.



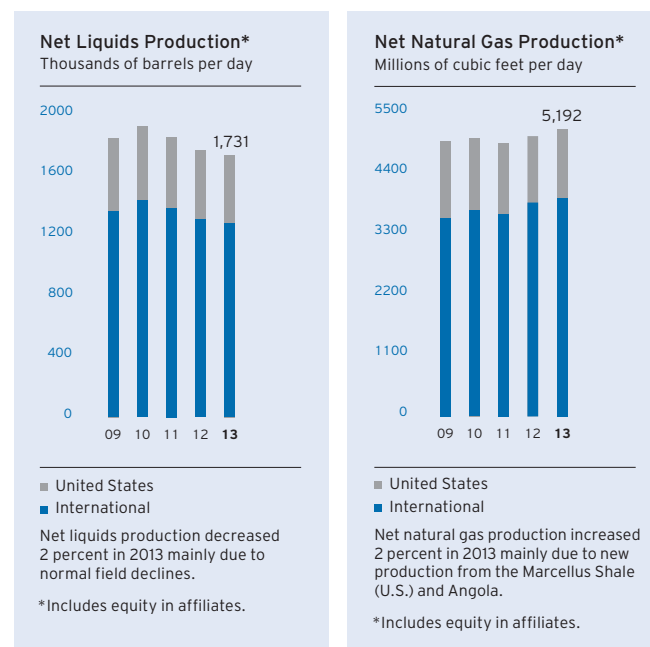
The chart above shows the trend in benchmark prices for Brent crude oil, West Texas Intermediate (WTI) crude oil and U.S. Henry Hub natural gas. The Brent price averaged \$109 per barrel for the full-year 2013, compared to \$112 in 2012. As of mid-February 2014, the Brent price was \$109 per barrel. The majority of the company's equity crude production is priced based on the Brent benchmark. The WTI price averaged \$98 per barrel for the full-year 2013, compared to \$94 in 2012. As of mid-February 2014, the WTI price was \$100 per barrel. WTI continued to trade at a discount to Brent in 2013 due to historically high inventories stemming from strong growth in domestic production and limitations on outbound pipeline capacity from the U.S. midcontinent. After narrowing during the first six months of 2013, the

WTI discount slowly widened into the fourth quarter as seasonal refinery turnarounds contributed to surplus supply conditions for WTI, while Brent prices were supported by supply disruptions due to international events.

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). During 2013, the differential between North American light and heavy crude oil remained below historical norms due to growth in U.S. light sweet crude production in the midcontinent region and pipeline capacity constraints at Cushing. Outside of North America, the light-heavy crude differential narrowed modestly in 2013 as supply disruptions in key producing countries tightened light sweet crude markets and additional heavy crude oil conversion capacity came online.

Chevron produces or shares in the production of heavy crude oil in California, Chad, 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 18 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. In the United States, prices at Henry Hub averaged \$3.70 per thousand cubic feet (MCF) during 2013, compared with \$2.71 during 2012. As of mid-February 2014, the Henry Hub spot price was \$5.53 per



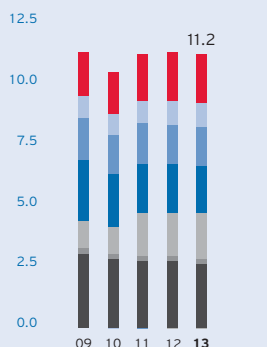
MCF. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced in North America.

Outside the United States, price changes for natural gas depend on a wide range of supply, demand and regulatory circumstances. 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. International natural gas realizations averaged \$5.91 per MCF during 2013, compared with \$5.99 per MCF during 2012. (See page 18 for the company's average natural gas realizations for the U.S. and international regions.)

The company's worldwide net oil-equivalent production in 2013 averaged 2.597 million barrels per day. About one-fifth of the company's net oil-equivalent production in 2013 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 2013 or 2012. At their December 2013 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 2014 will average approximately 2.610 million barrels per day, based on an average Brent price of \$109 per barrel for the full-year 2013. This estimate is subject to many factors and uncertainties, including 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.

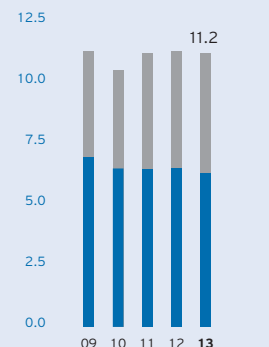
Net Proved Reserves
Billions of BOE



■ United States
■ Other Americas
■ Africa
■ Asia
■ Australia
■ Europe
■ Affiliates

Net proved reserves for consolidated companies and affiliated companies decreased 1 percent in 2013.

**Net Proved Reserves
Liquids vs. Natural Gas**
Billions of BOE



■ Natural Gas
■ Liquids

Reserve replacement rate in 2013 was 85 percent. Five-year average reserve replacement rate was 100 percent.

Refer to the "Results of Operations" section on pages 14 through 16 for additional discussion of the company's upstream business.

Refer to Table V beginning on page 73 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2011 and each year-end from 2011 through 2013, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2013.

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 these seeps have emerged. A Brazilian federal district prosecutor filed two civil lawsuits seeking \$10.7 billion in damages for each of the two seeps. On October 1, 2013, the Court dismissed the two civil lawsuits and approved a settlement under which Chevron and its consortium partners agreed to spend approximately \$43 million on social and environmental programs. On November 11, 2013, the Court announced that the settlement is final. The federal district prosecutor also filed criminal charges against Chevron and eleven Chevron employees. On February 19, 2013, the court dismissed the criminal matter, and on appeal, the appellate court reinstated two of the ten allegations, specifically those charges alleging environmental damage and failure to provide timely notification to authorities. The company is assessing its legal options. The company's ultimate exposure related to the incident is not currently determinable, but could be significant to net income in any one period.

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 14 through 16 for additional discussion of the company's downstream operations.

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

Operating Developments

Key operating developments and other events during 2013 and early 2014 included the following:

Upstream

Angola First shipment of liquefied natural gas was made from the Angola LNG Project.

Argentina Signed agreements advancing the Loma Campana Project to develop the Vaca Muerta Shale.

Australia Signed binding long-term LNG Sales and Purchase Agreements with two Asian customers. Binding long-term agreements now cover 85 percent of Chevron's equity LNG offtake from the Wheatstone Project.

Announced two natural gas discoveries in the Carnarvon Basin. These include discoveries at the 50 percent-owned and operated Kentish Knock South prospect in Block WA-365-P and the 50 percent-owned and operated Elfin prospect in Block WA-268-P.

Reached agreement to acquire interests in two onshore natural gas blocks in the Cooper Basin region of central Australia.

Acquired exploration interests in two blocks located in the deepwater Bight Basin offshore South Australia.

Brazil Confirmed the start of crude oil production from the Papa-Terra Field.

Awarded participation in a deepwater block in the Ceará Basin.

Canada Announced an agreement to acquire additional, complementary acreage in the Duvernay Shale.

Announced the successful conclusion of the initial twelve-well exploration drilling program in the liquids-rich portion of the Duvernay Shale located in western Canada.

Kurdistan Region of Iraq Announced the acquisition of an 80 percent interest and operatorship of the Qara Dagh Block.

Republic of the Congo Announced the final investment decision on the deepwater Moho Nord Project.

United States Announced a joint development agreement for additional Delaware Basin acreage and access to related infrastructure.

Announced a crude oil discovery at the Coronado prospect in the deepwater Gulf of Mexico.

Announced a successful production test of a St. Malo well in the deepwater Gulf of Mexico.

Downstream

South Korea The company's 50 percent-owned GS Caltex affiliate started commercial operations of its gas oil fluid catalytic cracking unit at the Yeosu Refinery.

United States The company's 50 percent-owned Chevron Phillips Chemical Company LLC (CPChem) announced a final investment decision on its U.S. Gulf Coast Petrochemicals Project. This project will include an ethane cracker with an annual design capacity of 1.5 million metric tons per year and two polyethylene facilities, each with an annual design capacity of 500,000 metric tons per year.

CPChem announced plans to expand annual ethylene production by 200 million pounds at its Sweeny complex in Old Ocean, Texas.

Other

Common Stock Dividends The quarterly common stock dividend was increased by 11.1 percent in April 2013 to \$1.00 per common share, making 2013 the 26th consecutive year that the company increased its annual dividend payment.

Common Stock Repurchase Program The company purchased \$5.0 billion of its common stock in 2013 under its share repurchase program. The program began in 2010 and has no set term or monetary limits.

Results of Operations

Major Operating Areas 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 11, beginning on page 43, 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	2013	2012	2011
Earnings	\$ 4,044	\$ 5,332	\$ 6,512

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.

U.S. upstream earnings of \$5.3 billion in 2012 decreased \$1.2 billion from 2011, primarily due to lower natural gas and crude oil realizations of \$340 million and \$200 million, respectively, lower crude oil production of \$240 million, and lower gains on asset sales of \$180 million.

The company's average realization for U.S. crude oil and natural gas liquids in 2013 was \$93.46 per barrel, compared with \$95.21 in 2012 and \$97.51 in 2011. The average natural gas realization was \$3.37 per thousand cubic feet in 2013, compared with \$2.64 and \$4.04 in 2012 and 2011, respectively.

Net oil-equivalent production in 2013 averaged 657,000 barrels per day, essentially unchanged from 2012 and down 3 percent from 2011. 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 decrease in production between 2012 and 2011 was associated with normal field declines and an absence of volumes associated with Cook Inlet, Alaska, assets sold in 2011. Partially offsetting this decrease was a ramp-up of projects in the Gulf of Mexico and Marcellus Shale and improved operational performance in the Gulf of Mexico. The net liquids component of oil-equivalent production for 2013 averaged 449,000 barrels per day, down 1 percent from 2012 and 3 percent from 2011. Net natural gas production averaged 1.2 billion cubic feet per day in 2013, up approximately 4 percent from 2012 and down about 3 percent from 2011. Refer to the "Selected Operating Data" table on page 18 for a three-year comparative of production volumes in the United States.

International Upstream

Millions of dollars	2013	2012	2011
Earnings*	\$ 16,765	\$ 18,456	\$ 18,274
*Includes foreign currency effects:	\$ 559	\$ (275)	\$ 211

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 expenses 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.

International upstream earnings were \$18.5 billion in 2012 compared with \$18.3 billion in 2011. The increase was mainly due to the gain of approximately \$1.4 billion on an asset exchange in Australia, higher natural gas realizations of about \$610 million and the nearly \$600 million gain on sale of an equity interest in the Wheatstone Project. Mostly offsetting these effects were lower crude oil volumes of \$1.3 billion and higher exploration expenses of \$430 million. Foreign currency effects decreased earnings by \$275 million in 2012, compared with an increase of \$211 million a year earlier.

The company's average realization for international crude oil and natural gas liquids in 2013 was \$100.26 per barrel, compared with \$101.88 in 2012 and \$101.53 in 2011. The average natural gas realization was \$5.91 per thousand cubic feet in 2013, compared with \$5.99 and \$5.39 in 2012 and 2011, respectively.

International net oil-equivalent production of 1.94 million barrels per day in 2013 decreased 1 percent from 2012 and decreased 3 percent from 2011. Project ramp-ups in Nigeria and Angola in 2013 were more than offset by normal field declines. The decline between 2012 and 2011 was a result of new production in Thailand and Nigeria in 2012 being more than offset by normal field declines, the shut-in of the Frade Field in Brazil and a major planned turnaround at Tengizchevroil.

The net liquids component of international oil-equivalent production was 1.3 million barrels per day in 2013, a decrease of approximately 2 percent from 2012 and a decrease of approximately 7 percent from 2011. International net natural gas production of 3.9 billion cubic feet per day in 2013 was up 2 percent from 2012 and up 8 percent from 2011.

Refer to the "Selected Operating Data" table, on page 18, for a three-year comparative of international production volumes.

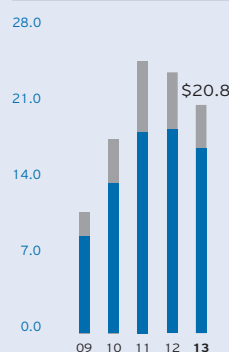
U.S. Downstream

Millions of dollars	2013	2012	2011
Earnings	\$ 787	\$ 2,048	\$1,506

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 the 50 percent-owned CPChem.

U.S. downstream operations earned \$2.0 billion in 2012, compared with \$1.5 billion in 2011. The increase was mainly due to higher margins on refined product sales of \$520 million and higher earnings of \$140 million from CPChem. These benefits were partly offset by higher operating expenses of \$130 million.

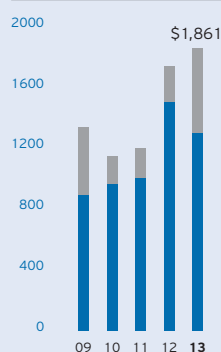
Worldwide Upstream Earnings
Billions of dollars



■ United States
■ International

Earnings decreased in 2013 mainly due to lower crude oil production volume and prices, higher operating expenses, and lower gains on asset sales.

Exploration Expenses
Millions of dollars (B/T)

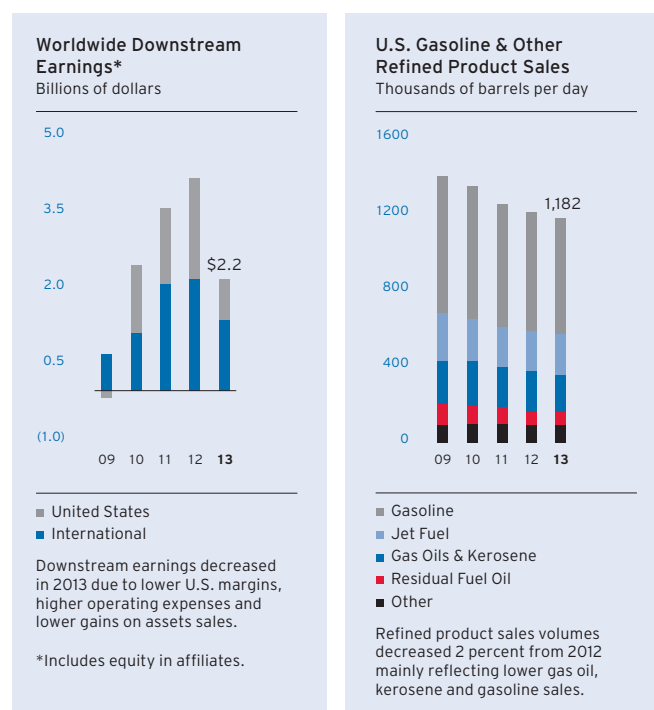


■ United States
■ International

Exploration expenses increased 8 percent from 2012 mainly due to higher dry hole expense in the U.S.

Refined product sales of 1.18 million barrels per day in 2013 declined 2 percent, mainly reflecting lower gas oil, kerosene and gasoline sales. Sales volumes of refined products were 1.21 million barrels per day in 2012, a decrease of 4 percent from 2011, mainly reflecting lower gasoline and fuel oil sales. U.S. branded gasoline sales of 517,000 barrels per day in 2013 were essentially unchanged from 2012 and 2011.

Refer to the "Selected Operating Data" table on page 18 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.



International Downstream

Millions of dollars	2013	2012	2011
Earnings*	\$ 1,450	\$ 2,251	\$ 2,085

*Includes foreign currency effects: \$ (76) \$ (173) \$ (65)

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 to \$173 million a year earlier.

International downstream earned \$2.3 billion in 2012, compared with \$2.1 billion in 2011. Earnings increased due to a favorable change in effects on derivative instruments of \$190 million and higher margins on refined product sales of

\$100 million. Foreign currency effects decreased earnings by \$173 million in 2012, compared with a decrease of \$65 million a year earlier.

Total refined product sales of 1.53 million barrels per day in 2013 declined 2 percent from 2012, mainly reflecting lower fuel oil and gasoline sales. Sales of 1.55 million barrels per day in 2012 declined 8 percent from 2011, primarily related to the third quarter 2011 sale of the company's refining and marketing assets in the United Kingdom and Ireland. Excluding the impact of 2011 asset sales, sales volumes were flat between the comparative periods.

Refer to the "Selected Operating Data" table, on page 18 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

Millions of dollars	2013	2012	2011
Net charges*	\$ (1,623)	\$ (1,908)	\$ (1,482)

*Includes foreign currency effects: \$ (9) \$ (6) \$ (25)

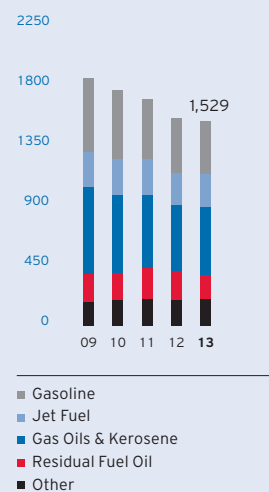
All Other includes mining operations, power and energy services, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, alternative fuels, and technology companies.

Net charges in 2013 decreased \$285 million from 2012, mainly due to lower corporate tax items and other corporate charges.

Net charges in 2012 increased \$426 million from 2011, mainly due to higher environmental reserve additions, corporate tax items and other corporate charges, partially offset by lower employee compensation and benefits expenses.

International Gasoline & Other Refined Product Sales*

Thousands of barrels per day



Sales volumes of refined products were down 2 percent from 2012 mainly due to lower fuel oil and gasoline sales.

*Includes equity in affiliates.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

<i>Millions of dollars</i>	2013	2012	2011
Sales and other operating revenues	\$ 220,156	\$ 230,590	\$ 244,371

Sales and other operating revenues decreased in 2013 mainly due to lower refined product prices and lower crude oil volumes and prices. The decrease between 2012 and 2011 was mainly due to the 2011 sale of the company's refining and marketing assets in the United Kingdom and Ireland, and lower crude oil volumes.

<i>Millions of dollars</i>	2013	2012	2011
Income from equity affiliates	\$ 7,527	\$ 6,889	\$ 7,363

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.

Income from equity affiliates decreased in 2012 from 2011 mainly due to lower upstream-related earnings from Tengizchevroil in Kazakhstan as a result of lower crude oil production, and higher operating expenses at Angola LNG Limited and Petropiar in Venezuela. Downstream-related earnings were higher between comparative periods, primarily due to higher margins at CPChem.

Refer to Note 12, beginning on page 45, for a discussion of Chevron's investments in affiliated companies.

<i>Millions of dollars</i>	2013	2012	2011
Other income	\$ 1,165	\$ 4,430	\$ 1,972

Other income of \$1.2 billion in 2013 included net gains from asset sales of \$710 million before-tax. Other income in 2012 and 2011 included net gains from asset sales of \$4.2 billion and \$1.5 billion before-tax, respectively. Interest income was \$136 million in 2013, \$166 million in 2012 and \$145 million in 2011. Foreign currency effects increased other income by \$103 million in 2013, while decreasing other income by \$207 million in 2012 and increasing other income by \$103 million in 2011.

<i>Millions of dollars</i>	2013	2012	2011
Purchased crude oil and products	\$ 134,696	\$ 140,766	\$ 149,923

Crude oil and product purchases of \$134.7 billion were down in 2013 mainly due to lower prices for refined products and lower volumes for crude oil, partially offset by higher refined product volumes. Crude oil and product purchases in 2012 decreased by \$9.2 billion from the prior year mainly due to the 2011 sale of the company's refining and marketing assets in the United Kingdom and Ireland and lower natural gas prices.

<i>Millions of dollars</i>	2013	2012	2011
Operating, selling, general and administrative expenses	\$ 29,137	\$ 27,294	\$ 26,394

Operating, selling, general and administrative expenses increased \$1.8 billion between 2013 and 2012 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.

Operating, selling, general and administrative expenses increased \$900 million between 2012 and 2011 mainly due to higher contract labor and professional services of \$590 million, and higher employee compensation and benefits of \$280 million.

<i>Millions of dollars</i>	2013	2012	2011
Exploration expense	\$ 1,861	\$ 1,728	\$ 1,216

Exploration expenses in 2013 increased from 2012 mainly due to higher charges for well write-offs.

Exploration expenses in 2012 increased from 2011 mainly due to higher geological and geophysical costs and well write-offs.

<i>Millions of dollars</i>	2013	2012	2011
Depreciation, depletion and amortization	\$ 14,186	\$ 13,413	\$ 12,911

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. The increase in 2012 from 2011 was mainly due to higher depreciation rates for certain oil and gas producing fields, partially offset by lower production levels.

<i>Millions of dollars</i>	2013	2012	2011
Taxes other than on income	\$ 13,063	\$ 12,376	\$ 15,628

Taxes other than on income increased in 2013 from 2012 mainly 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. Taxes other than on income decreased in 2012 from 2011 primarily due to lower import duties in the United Kingdom reflecting the sale of the company's refining and marketing assets in the United Kingdom and Ireland in 2011. Partially offsetting the decrease were excise taxes associated with consolidation of Star Petroleum Refining Company beginning June 2012.

Millions of dollars	2013	2012	2011
Income tax expense	\$ 14,308	\$ 19,996	\$ 20,626

Effective income tax rates were 40 percent in 2013, 43 percent in 2012 and 43 percent in 2011. The decrease in the effective tax rate between 2013 and 2012 was 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.

The rate was unchanged between 2012 and 2011. The impact of lower effective tax rates in international upstream operations was offset by foreign currency remeasurement impacts between periods. For international upstream, the lower effective tax rates in the 2012 period were driven primarily by the effects of asset sales, one-time tax benefits and reduced withholding taxes, which were partially offset by a lower utilization of tax credits during the year.

Selected Operating Data^{1,2}

	2013	2012	2011
U.S. Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD)	449	455	465
Net Natural Gas Production (MMCFPD) ³	1,246	1,203	1,279
Net Oil-Equivalent Production (MBOEPD)	657	655	678
Sales of Natural Gas (MMCFPD)	5,483	5,470	5,836
Sales of Natural Gas Liquids (MBPD)	17	16	15
Revenues From Net Production			
Liquids (\$/Bbl)	\$ 93.46	\$ 95.21	\$ 97.51
Natural Gas (\$/MCF)	\$ 3.37	\$ 2.64	\$ 4.04
International Upstream			
Net Crude Oil and Natural Gas			
Liquids Production (MBPD) ⁴	1,282	1,309	1,384
Net Natural Gas Production (MMCFPD) ³	3,946	3,871	3,662
Net Oil-Equivalent Production (MBOEPD) ⁴	1,940	1,955	1,995
Sales of Natural Gas (MMCFPD)	4,251	4,315	4,361
Sales of Natural Gas Liquids (MBPD)	26	24	24
Revenues From Liftings			
Liquids (\$/Bbl)	\$100.26	\$101.88	\$101.53
Natural Gas (\$/MCF)	\$ 5.91	\$ 5.99	\$ 5.39
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD) ⁴			
United States	657	655	678
International	1,940	1,955	1,995
Total	2,597	2,610	2,673
U.S. Downstream			
Gasoline Sales (MBPD) ⁵	613	624	649
Other Refined Product Sales (MBPD)	569	587	608
Total Refined Product Sales (MBPD)	1,182	1,211	1,257
Sales of Natural Gas Liquids (MBPD)	125	141	146
Refinery Input (MBPD)	774	833	854
International Downstream			
Gasoline Sales (MBPD) ⁵	398	412	447
Other Refined Product Sales (MBPD)	1,131	1,142	1,245
Total Refined Product Sales (MBPD) ⁶	1,529	1,554	1,692
Sales of Natural Gas Liquids (MBPD)	62	64	63
Refinery Input (MBPD) ⁷	864	869	933

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 ⁸	72	65	69
International ⁸	452	457	447

⁴ Includes: Canada – synthetic oil 43 43 40
Venezuela affiliate – synthetic oil 25 17 32

⁵ Includes branded and unbranded gasoline.

⁶ Includes sales of affiliates (MBPD): 471 522 556

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.

⁸ 2012 and 2011 conform to 2013 presentation.

Liquidity and Capital Resources

Cash, Cash Equivalents, Time Deposits and Marketable Securities Total balances were \$16.5 billion and \$21.9 billion at December 31, 2013 and 2012, respectively. Cash provided by operating activities in 2013 was \$35.0 billion, compared with \$38.8 billion in 2012 and \$41.1 billion in 2011. Cash provided by operating activities was net of contributions to employee pension plans of approximately \$1.2 billion, \$1.2 billion and \$1.5 billion in 2013, 2012 and 2011, respectively. Cash provided by investing activities included proceeds and deposits related to asset sales of \$1.1 billion in 2013, \$2.8 billion in 2012, and \$3.5 billion in 2011.

Restricted cash of \$1.2 billion and \$1.5 billion at December 31, 2013 and 2012, 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 \$7.5 billion in 2013, \$6.8 billion in 2012 and \$6.1 billion in 2011. In April 2013, the company increased its quarterly dividend by 11.1 percent to \$1.00 per common share.

Debt and Capital Lease Obligations Total debt and capital lease obligations were \$20.4 billion at December 31, 2013, up from \$12.2 billion at year-end 2012.

The \$8.2 billion increase in total debt and capital lease obligations during 2013 included a \$6 billion bond issuance in June 2013, 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 \$8.4 billion at December 31, 2013, compared with \$6.0 billion at year-end 2012. Of these amounts, \$8.0 billion and \$5.9 billion were reclassified to long-term at the end of each period, respectively. At year-end 2013, settlement of these obligations was not expected to require the use of working capital in 2014, 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 Corpora-

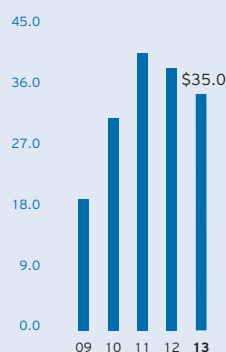
tion and are rated AA by Standard & Poor’s Corporation and Aa1 by Moody’s Investors Service. The company’s U.S. commercial paper is rated A-1+ by Standard & Poor’s and P-1 by Moody’s. All of these ratings denote high-quality, investment-grade securities.

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. The company also can modify capital spending plans during any extended periods of low prices for crude oil and natural gas and narrow margins for refined products and commodity chemicals to provide flexibility to continue paying the common stock dividend and maintain the company’s high-quality debt ratings.

Committed Credit Facilities Information related to committed credit facilities is included in Note 16 to the Consolidated Financial Statements, Short-Term Debt, beginning on page 53.

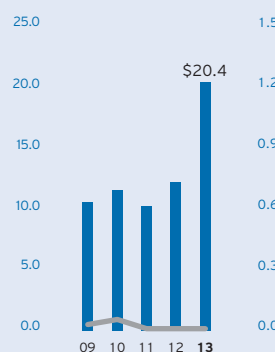
Common Stock Repurchase Program In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits. The company expects to repurchase between \$500 million and \$2 billion of its common shares per quarter, at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. During 2013, the company purchased 41.6 million common shares for \$5.0 billion. From the inception of the program through 2013, the company had purchased 139.3 million shares for \$15.0 billion.

Cash Provided by Operating Activities
Billions of dollars



Operating cash flows were \$3.8 billion lower than 2012, primarily reflecting lower earnings.

Total Interest Expense & Total Debt at Year-End
Billions of dollars



■ Total Interest Expense (right scale)
■ Total Debt (left scale)

Total debt increased \$8.2 billion during 2013 to \$20.4 billion. All interest expense was capitalized as part of the cost of major projects in 2013, 2012 and 2011.

Capital and Exploratory Expenditures

Millions of dollars	2013			2012			2011		
	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream ¹	\$ 8,480	\$ 29,378	\$ 37,858	\$ 8,531	\$ 21,913	\$ 30,444	\$ 8,318	\$ 17,554	\$ 25,872
Downstream	1,986	1,189	3,175	1,913	1,259	3,172	1,461	1,150	2,611
All Other	821	23	844	602	11	613	575	8	583
Total	\$ 11,287	\$ 30,590	\$ 41,877	\$ 11,046	\$ 23,183	\$ 34,229	\$ 10,354	\$ 18,712	\$ 29,066
Total, Excluding Equity in Affiliates	\$ 10,562	\$ 28,617	\$ 39,179	\$ 10,738	\$ 21,374	\$ 32,112	\$ 10,077	\$ 17,294	\$ 27,371

¹ Excludes the acquisition of Atlas Energy, Inc. in 2011.

Capital and Exploratory Expenditures Total expenditures for 2013 were \$41.9 billion, including \$2.7 billion for the company's share of equity-affiliate expenditures, which did not require cash outlays by the company. In 2012 and 2011, expenditures were \$34.2 billion and \$29.1 billion, respectively, including the company's share of affiliates' expenditures of \$2.1 billion and \$1.7 billion, respectively.

Expenditures for 2013 include approximately \$4 billion for major resource acquisitions in Argentina, Australia, the Permian Basin and the Kurdistan Region of Iraq, along with additional acreage in the Duvernay Shale and interests in the Kitimat LNG Project in Canada. 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 \$41.9 billion of expenditures in 2013, 90 percent, or \$37.9 billion, was related to upstream activities. Approxi-

mately 89 percent was expended for upstream operations in 2012 and 2011. International upstream accounted for 78 percent of the worldwide upstream investment in 2013, 72 percent in 2012 and 68 percent in 2011. These amounts exclude the acquisition of Atlas Energy, Inc. in 2011.

The company estimates that 2014 capital and exploratory expenditures will be \$39.8 billion, including \$4.8 billion of spending by affiliates. Approximately 90 percent of the total, or \$35.8 billion, is budgeted for exploration and production activities. Approximately \$27.9 billion, or 78 percent, of this amount is for projects outside the United States. Spending in 2014 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, and for focused exploration and appraisal activities.

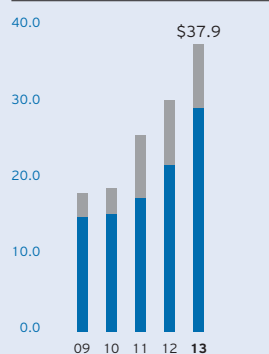
Worldwide downstream spending in 2014 is estimated at \$3.1 billion, with \$1.8 billion for projects in the United States. Major capital outlays include projects under construction at refineries in the United States and expansion of additives production capacity in Singapore. Additional investments are expected to be funded by CPCChem for chemicals projects in the United States.

Investments in technology companies, power and energy services, and other corporate businesses in 2014 are budgeted at \$1 billion.

Noncontrolling Interests The company had noncontrolling interests of \$1.3 billion at both December 31, 2013 and 2012. Distributions to noncontrolling interests totaled \$99 million and \$41 million in 2013 and 2012, respectively.

Pension Obligations Information related to pension plan contributions is included on page 61 in Note 21 to the Consolidated Financial Statements under the heading "Cash Contributions and Benefit Payments."

Upstream – Capital & Exploratory Expenditures*
Billions of dollars

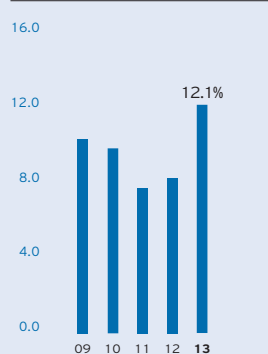


■ United States
■ International

Exploration and production expenditures were 24 percent higher than 2012.

*Includes equity in affiliates. Excludes the acquisition of Atlas Energy, Inc. in 2011.

Ratio of Total Debt to Total Debt-Plus-Chevron Corporation Stockholders' Equity
Percent



The ratio increased to 12.1 percent at the end of 2013 due to higher debt, partially offset by an increase in stockholders' equity.

Financial Ratios

Financial Ratios

	At December 31		
	2013	2012	2011
Current Ratio	1.5	1.6	1.6
Interest Coverage Ratio	126.2	191.3	165.4
Debt Ratio	12.1%	8.2%	7.7%

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 2013, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately \$9.1 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 2013 was lower than 2012 and 2011 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 2013 was higher than 2012 and 2011 due to higher debt, partially offset by a higher stockholder’s equity balance.

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

Direct Guarantees

Millions of dollars	Commitment Expiration by Period				
	Total	2014	2015–2016	2017–2018	After 2018
Guarantee of non-consolidated affiliate or joint-venture obligations	\$ 524	\$ 38	\$ 76	\$ 76	\$ 334

The company’s guarantee of \$524 million is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 14-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 63 in Note 23 to the Consolidated Financial Statements under the heading “Indemnifications.”

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

The company and its subsidiaries have certain other 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: 2014 – \$4.2 billion; 2015 – \$4.5 billion; 2016 – \$3.2 billion; 2017 – \$2.6 billion; 2018 – \$2.2 billion; 2019 and after – \$6.9 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$3.6 billion in 2013, \$3.6 billion in 2012 and \$6.6 billion in 2011.

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

Contractual Obligations¹

Millions of dollars	Payments Due by Period				
	Total	2014	2015–2016	2017–2018	After 2018
On Balance Sheet: ²					
Short-Term Debt ³	\$ 374	\$ 374	\$ —	\$ —	\$ —
Long-Term Debt ³	19,960	—	8,750	4,000	7,210
Noncancelable Capital					
Lease Obligations	177	45	52	34	46
Interest	2,611	335	659	606	1,011
Off Balance Sheet:					
Noncancelable Operating					
Lease Obligations	3,709	798	1,327	778	806
Throughput and					
Take-or-Pay Agreements ⁴	15,320	2,679	4,372	2,587	5,682
Other Unconditional					
Purchase Obligations ⁴	8,257	1,527	3,386	2,188	1,156

¹ Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 21 beginning on page 56.

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 these liabilities may become payable. The company does not expect settlement of such liabilities will 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 2015–2016 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.

Financial and Derivative Instrument Market Risk

The market risk associated with the company’s portfolio of financial and derivative instruments is discussed on the next page. 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 2013 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 2013.

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 have been approved 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 2013 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, 2013 and 2012 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, 2013.

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 2013, 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 12 of the Consolidated Financial Statements, page 46, 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 47 in Note 14 to the Consolidated Financial Statements under the heading "MTBE."

Ecuador Information related to Ecuador matters is included in Note 14 to the Consolidated Financial Statements under the heading "Ecuador," beginning on page 47.

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.

Millions of dollars	2013	2012	2011
Balance at January 1	\$ 1,403	\$ 1,404	\$ 1,507
Net Additions	488	428	343
Expenditures	(435)	(429)	(446)
Balance at December 31	\$ 1,456	\$ 1,403	\$ 1,404

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 \$14.3 billion for asset retirement obligations at year-end 2013 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 2013 environmental expenditures. Refer to Note 23 on pages 63 through 64 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 24 on page 64 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 19 to the Consolidated Financial Statements, "Accounting for Suspended Exploratory Wells," beginning on page 54.

Income Taxes Information related to income tax contingencies is included on pages 51 through 53 in Note 15 and pages 62 through 63 in Note 23 to the Consolidated Financial Statements under the heading "Income Taxes."

Other Contingencies Information related to other contingencies is included on page 64 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.

Most of the costs of complying with laws and regulations pertaining to company operations and products are embed-

ded 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 2013 at approximately \$2.7 billion for its consolidated companies. Included in these expenditures were approximately \$1.0 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 2014, total worldwide environmental capital expenditures are estimated at \$1.1 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. All 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 and economic conditions.

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 - Proved reserves are used in amortizing capitalized costs related to oil and gas producing activities on the unit-of-production (UOP) method. Capitalized exploratory drilling and development costs are depreciated on a UOP basis using proved developed reserves. Acquisition costs of proved properties are amortized on a UOP basis using total proved reserves. During 2013, Chevron's UOP Depreciation, Depletion and Amortization (DD&A) for oil and gas properties was \$11.6 billion, and proved developed reserves at the beginning of 2013 were 4.8 billion

barrels. 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 2013 would have increased by approximately \$600 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 73, for the changes in proved reserve estimates for the three years ending December 31, 2013, 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, 2013.

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 41 and to the section on Properties, Plant and Equipment in Note 1, "Summary of Significant Accounting Policies," beginning on page 35.

No material individual impairments of PP&E or Investments were recorded for the three years ending December 31, 2013. 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.

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. When such a decline is deemed to be other than temporary, an impairment charge is recorded to the income statement for the difference between the investment's carrying value and its estimated fair value at the time.

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. 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.

From time to time, the company performs impairment reviews and determines 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. 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.

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 2013 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 64 for additional discussions on asset retirement obligations.

Pension and Other Postretirement Benefit Plans

Note 21, beginning on page 56, 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 beginning on page 56 in Note 21 under the relevant headings. Actual rates of return on plan assets and discount rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

For 2013, the company used an expected long-term rate of return of 7.5 percent and a discount rate of 3.6 percent for U.S. pension plans. For the 10 years ending December 31, 2013, actual asset returns averaged 6.4 percent for the plan. The actual return for 2013 was more than 7.5 percent and was associated with a continuing recovery in the financial markets during the year. Additionally, with the exception of two other years within this 10-year period, actual asset returns for this plan equaled or exceeded 7.5 percent.

Total pension expense for 2013 was \$1.3 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 59 percent of companywide pension expense, would have reduced total pension plan expense for 2013 by approximately \$85 million. A 1 percent increase in the discount rate for this same plan would have reduced pension expense for 2013 by approximately \$190 million.

The aggregate funded status recognized at December 31, 2013, was a net liability of approximately \$2.4 billion. An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan. At December 31, 2013, the company used a discount rate of 4.3 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 59 percent of the companywide pension obligation, would have reduced the plan obligation by approximately \$345 million, which would have increased the plan's overfunded status from approximately \$0.4 billion to \$0.7 billion.

For the company's OPEB plans, expense for 2013 was \$218 million, and the total liability, which reflected the unfunded status of the plans at the end of 2013, was \$3.1 billion. For the main U.S. OPEB plan, the company used a 3.9 percent discount rate to measure expense in 2013, and a 4.7 percent discount rate to measure the benefit obligations at December 31, 2013. Discount rate changes, similar to those used in the pension sensitivity analysis, resulted in an immaterial impact on 2013 OPEB expense and OPEB liabilities at the end of 2013. For information on the sensitivity of the health care cost-trend rate, refer to page 59 in Note 21 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 58 in Note 21 for a description of the method used to amortize the \$5.2 billion of before-tax actuarial losses recorded by the company as of December 31, 2013, and an estimate of the costs to be recognized in expense during 2014. In addition, information related to company contributions is included on page 61 in Note 21 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 62. 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, 2013.

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 18, on page 54 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>	2013				2012			
	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	\$ 53,950	\$ 56,603	\$ 55,307	\$ 54,296	\$ 56,254	\$ 55,660	\$ 59,780	\$ 58,896
Income from equity affiliates	1,824	1,635	1,784	2,284	1,815	1,274	2,091	1,709
Other income	384	265	278	238	2,483	1,110	737	100
Total Revenues and Other Income	56,158	58,503	57,369	56,818	60,552	58,044	62,608	60,705
Costs and Other Deductions								
Purchased crude oil and products	32,691	34,822	34,273	32,910	33,959	33,982	36,772	36,053
Operating expenses	6,521	6,066	6,278	5,762	6,273	5,694	5,420	5,183
Selling, general and administrative expenses	1,176	1,197	1,139	998	1,182	1,352	1,250	940
Exploration expenses	726	559	329	247	357	475	493	403
Depreciation, depletion and amortization	3,635	3,658	3,412	3,481	3,554	3,370	3,284	3,205
Taxes other than on income ¹	3,211	3,366	3,349	3,137	3,251	3,239	3,034	2,852
Total Costs and Other Deductions	47,960	49,668	48,780	46,535	48,576	48,112	50,253	48,636
Income Before Income Tax Expense	8,198	8,835	8,589	10,283	11,976	9,932	12,355	12,069
Income Tax Expense	3,240	3,839	3,185	4,044	4,679	4,624	5,123	5,570
Net Income	\$ 4,958	\$ 4,996	\$ 5,404	\$ 6,239	\$ 7,297	\$ 5,308	\$ 7,232	\$ 6,499
Less: Net income attributable to noncontrolling interests	28	46	39	61	52	55	22	28
Net Income Attributable to Chevron Corporation	\$ 4,930	\$ 4,950	\$ 5,365	\$ 6,178	\$ 7,245	\$ 5,253	\$ 7,210	\$ 6,471
Per Share of Common Stock								
Net Income Attributable to Chevron Corporation								
– Basic	\$ 2.60	\$ 2.58	\$ 2.80	\$ 3.20	\$ 3.73	\$ 2.71	\$ 3.68	\$ 3.30
– Diluted	\$ 2.57	\$ 2.57	\$ 2.77	\$ 3.18	\$ 3.70	\$ 2.69	\$ 3.66	\$ 3.27
Dividends	\$ 1.00	\$ 1.00	\$ 1.00	\$ 0.90	\$ 0.90	\$ 0.90	\$ 0.90	\$ 0.81
Common Stock Price Range – High²	\$ 125.65	\$ 127.83	\$ 127.40	\$ 121.56	\$ 118.38	\$ 118.53	\$ 108.79	\$ 112.28
– Low²	\$ 114.44	\$ 117.22	\$ 114.12	\$ 108.74	\$ 100.66	\$ 103.29	\$ 95.73	\$ 102.08
¹ Includes excise, value-added and similar taxes:	\$ 2,128	\$ 2,223	\$ 2,108	\$ 2,033	\$ 2,131	\$ 2,163	\$ 1,929	\$ 1,787
² Intraday price.								

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 10, 2014, stockholders of record numbered approximately 160,000. 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 *Internal Control – Integrated Framework* (1992) 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, 2013.

On May 14, 2013, COSO published an updated *Internal Control - Integrated Framework* (2013) and related illustrative documents. As of December 31, 2013, the company is utilizing the original framework published in 1992. The transition period for adoption of the updated framework ends December 15, 2014.

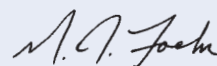
The effectiveness of the company's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.



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 21, 2014

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, 2013, and December 31, 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control – Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, 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 21, 2014

Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2013	2012	2011
Revenues and Other Income			
Sales and other operating revenues*	\$ 220,156	\$ 230,590	\$ 244,371
Income from equity affiliates	7,527	6,889	7,363
Other income	1,165	4,430	1,972
Total Revenues and Other Income	228,848	241,909	253,706
Costs and Other Deductions			
Purchased crude oil and products	134,696	140,766	149,923
Operating expenses	24,627	22,570	21,649
Selling, general and administrative expenses	4,510	4,724	4,745
Exploration expenses	1,861	1,728	1,216
Depreciation, depletion and amortization	14,186	13,413	12,911
Taxes other than on income*	13,063	12,376	15,628
Total Costs and Other Deductions	192,943	195,577	206,072
Income Before Income Tax Expense	35,905	46,332	47,634
Income Tax Expense	14,308	19,996	20,626
Net Income	21,597	26,336	27,008
Less: Net income attributable to noncontrolling interests	174	157	113
Net Income Attributable to Chevron Corporation	\$ 21,423	\$ 26,179	\$ 26,895
Per Share of Common Stock			
Net Income Attributable to Chevron Corporation			
– Basic	\$ 11.18	\$ 13.42	\$ 13.54
– Diluted	\$ 11.09	\$ 13.32	\$ 13.44

*Includes excise, value-added and similar taxes.

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2013	2012	2011
Net Income	\$ 21,597	\$ 26,336	\$ 27,008
Currency translation adjustment			
Unrealized net change arising during period	42	23	17
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	(7)	1	(11)
Derivatives			
Net derivatives (loss) gain on hedge transactions	(111)	20	20
Reclassification to net income of net realized (gain) loss	(1)	(14)	9
Income taxes on derivatives transactions	39	(3)	(10)
Total	(73)	3	19
Defined benefit plans			
Actuarial gain (loss)			
Amortization to net income of net actuarial loss and settlements	866	920	773
Actuarial gain (loss) arising during period	3,379	(1,180)	(3,250)
Prior service credits (cost)			
Amortization to net income of net prior service credits	(27)	(61)	(26)
Prior service credits (cost) arising during period	60	(142)	(27)
Defined benefit plans sponsored by equity affiliates	164	(54)	(81)
Income taxes on defined benefit plans	(1,614)	143	1,030
Total	2,828	(374)	(1,581)
Other Comprehensive Gain (Loss), Net of Tax	2,790	(347)	(1,556)
Comprehensive Income	24,387	25,989	25,452
Comprehensive income attributable to noncontrolling interests	(174)	(157)	(113)
Comprehensive Income Attributable to Chevron Corporation	\$ 24,213	\$ 25,832	\$ 25,339

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

Millions of dollars, except per-share amounts

	At December 31	
	2013	2012
Assets		
Cash and cash equivalents	\$ 16,245	\$ 20,939
Time deposits	8	708
Marketable securities	263	266
Accounts and notes receivable (less allowance: 2013 – \$62; 2012 – \$80)	21,622	20,997
Inventories:		
Crude oil and petroleum products	3,879	3,923
Chemicals	491	475
Materials, supplies and other	2,010	1,746
Total inventories	6,380	6,144
Prepaid expenses and other current assets	5,732	6,666
Total Current Assets	50,250	55,720
Long-term receivables, net	2,833	3,053
Investments and advances	25,502	23,718
Properties, plant and equipment, at cost	296,433	263,481
Less: Accumulated depreciation, depletion and amortization	131,604	122,133
Properties, plant and equipment, net	164,829	141,348
Deferred charges and other assets	5,120	4,503
Goodwill	4,639	4,640
Assets held for sale	580	–
Total Assets	\$ 253,753	\$ 232,982
Liabilities and Equity		
Short-term debt	\$ 374	\$ 127
Accounts payable	22,815	22,776
Accrued liabilities	5,402	5,738
Federal and other taxes on income	3,092	4,341
Other taxes payable	1,335	1,230
Total Current Liabilities	33,018	34,212
Long-term debt	19,960	11,966
Capital lease obligations	97	99
Deferred credits and other noncurrent obligations	22,982	21,502
Noncurrent deferred income taxes	21,301	17,672
Noncurrent employee benefit plans	5,968	9,699
Total Liabilities	103,326	95,150
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, 2013 and 2012)	1,832	1,832
Capital in excess of par value	15,713	15,497
Retained earnings	173,677	159,730
Accumulated other comprehensive loss	(3,579)	(6,369)
Deferred compensation and benefit plan trust	(240)	(282)
Treasury stock, at cost (2013 – 529,073,512 shares; 2012 – 495,978,691 shares)	(38,290)	(33,884)
Total Chevron Corporation Stockholders' Equity	149,113	136,524
Noncontrolling interests	1,314	1,308
Total Equity	150,427	137,832
Total Liabilities and Equity	\$ 253,753	\$ 232,982

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Millions of dollars

	Year ended December 31		
	2013	2012	2011
Operating Activities			
Net Income	\$ 21,597	\$ 26,336	\$ 27,008
Adjustments			
Depreciation, depletion and amortization	14,186	13,413	12,911
Dry hole expense	683	555	377
Distributions less than income from equity affiliates	(1,178)	(1,351)	(570)
Net before-tax gains on asset retirements and sales	(639)	(4,089)	(1,495)
Net foreign currency effects	(103)	207	(103)
Deferred income tax provision	1,876	2,015	1,589
Net (increase) decrease in operating working capital	(1,331)	363	2,318
Decrease (increase) in long-term receivables	183	(169)	(150)
(Increase) decrease in other deferred charges	(321)	1,047	341
Cash contributions to employee pension plans	(1,194)	(1,228)	(1,467)
Other	1,243	1,713	336
Net Cash Provided by Operating Activities	35,002	38,812	41,095
Investing Activities			
Acquisition of Atlas Energy	—	—	(3,009)
Advance to Atlas Energy	—	—	(403)
Capital expenditures	(37,985)	(30,938)	(26,500)
Proceeds and deposits related to asset sales	1,143	2,777	3,517
Net sales (purchases) of time deposits	700	3,250	(1,104)
Net sales (purchases) of marketable securities	3	(3)	(74)
Repayment of loans by equity affiliates	314	328	339
Net sales (purchases) of other short-term investments	216	(210)	(255)
Net Cash Used for Investing Activities	(35,609)	(24,796)	(27,489)
Financing Activities			
Net borrowings of short-term obligations	2,378	264	23
Proceeds from issuances of long-term debt	6,000	4,007	377
Repayments of long-term debt and other financing obligations	(132)	(2,224)	(2,769)
Cash dividends – common stock	(7,474)	(6,844)	(6,136)
Distributions to noncontrolling interests	(99)	(41)	(71)
Net purchases of treasury shares	(4,494)	(4,142)	(3,193)
Net Cash Used for Financing Activities	(3,821)	(8,980)	(11,769)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(266)	39	(33)
Net Change in Cash and Cash Equivalents	(4,694)	5,075	1,804
Cash and Cash Equivalents at January 1	20,939	15,864	14,060
Cash and Cash Equivalents at December 31	\$ 16,245	\$ 20,939	\$ 15,864

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	2013		2012		2011	
	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		\$ 15,497		\$ 15,156		\$ 14,796
Treasury stock transactions		216		341		360
Balance at December 31		\$ 15,713		\$ 15,497		\$ 15,156
Retained Earnings						
Balance at January 1		\$ 159,730		\$ 140,399		\$ 119,641
Net income attributable to Chevron Corporation		21,423		26,179		26,895
Cash dividends on common stock		(7,474)		(6,844)		(6,136)
Stock dividends		(3)		(3)		(3)
Tax (charge) benefit from dividends paid on unallocated ESOP shares and other		1		(1)		2
Balance at December 31		\$ 173,677		\$ 159,730		\$ 140,399
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		\$ (65)		\$ (88)		\$ (105)
Change during year		42		23		17
Balance at December 31		\$ (23)		\$ (65)		\$ (88)
Unrealized net holding (loss) gain on securities						
Balance at January 1		\$ 1		\$ —		\$ 11
Change during year		(7)		1		(11)
Balance at December 31		\$ (6)		\$ 1		\$ —
Net derivatives gain (loss) on hedge transactions						
Balance at January 1		\$ 125		\$ 122		\$ 103
Change during year		(73)		3		19
Balance at December 31		\$ 52		\$ 125		\$ 122
Pension and other postretirement benefit plans						
Balance at January 1		\$ (6,430)		\$ (6,056)		\$ (4,475)
Change during year		2,828		(374)		(1,581)
Balance at December 31		\$ (3,602)		\$ (6,430)		\$ (6,056)
Balance at December 31		\$ (3,579)		\$ (6,369)		\$ (6,022)
Deferred Compensation and Benefit Plan Trust						
Deferred Compensation						
Balance at January 1		\$ (42)		\$ (58)		\$ (71)
Net reduction of ESOP debt and other		42		16		13
Balance at December 31		—		(42)		(58)
Benefit Plan Trust (Common Stock)	14,168	(240)	14,168	(240)	14,168	(240)
Balance at December 31	14,168	\$ (240)	14,168	\$ (282)	14,168	\$ (298)
Treasury Stock at Cost						
Balance at January 1	495,979	\$ (33,884)	461,510	\$ (29,685)	435,196	\$ (26,411)
Purchases	41,676	(5,004)	46,669	(5,004)	42,424	(4,262)
Issuances – mainly employee benefit plans	(8,581)	598	(12,200)	805	(16,110)	988
Balance at December 31	529,074	\$ (38,290)	495,979	\$ (33,884)	461,510	\$ (29,685)
Total Chevron Corporation Stockholders' Equity at December 31		\$ 149,113		\$ 136,524		\$ 121,382
Noncontrolling Interests		\$ 1,314		\$ 1,308		\$ 799
Total Equity		\$ 150,427		\$ 137,832		\$ 122,181

See accompanying Notes to the Consolidated Financial Statements.

Note 1**Summary of Significant Accounting Policies**

General 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 project. Downstream operations relate primarily to refining crude oil into petroleum products; marketing of crude oil and refined products; transporting 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 additives for fuels and lubricant oils.

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 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.

Note 1 Summary of Significant Accounting Policies - Continued

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 19, beginning on page 54, 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, 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 40, 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 64, 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 64, 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 30. 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, 2013, are reflected in the table below.

Changes in Accumulated Other Comprehensive Losses by Component¹

	Year Ending December 31, 2013					
	Currency Translation Adjustment	Unrealized Holding Gains (Losses) on Securities	Derivatives	Defined Benefit Plans	Total	
Balance at January 1	\$ (65)	\$ 1	\$ 125	\$ (6,430)	\$	(6,369)
Components of Other Comprehensive						
Income (Loss):						
Before Reclassifications	42	(7)	(72)	2,302		2,265
Reclassifications ²	—	—	(1)	526		525
Net Other Comprehensive Income (Loss)	42	(7)	(73)	2,828		2,790
Balance at December 31	\$ (23)	\$ (6)	\$ 52	\$ (3,602)	\$	(3,579)

¹ All amounts are net of tax.

² Refer to Note 21, Employee Benefits for reclassified components totaling \$839 that are included in employee benefit costs for the year ending December 31, 2013. Related income taxes for the same period, totaling \$313, are reflected in Income Tax Expense on the Consolidated Statement of Income. All other reclassified amounts were insignificant.

Note 3 Noncontrolling Interests

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 2013, 2012 and 2011 is as follows:

	2013	2012	2011
Balance at January 1	\$ 1,308	\$ 799	\$ 730
Net income	174	157	113
Distributions to noncontrolling interests	(99)	(41)	(71)
Other changes, net*	(69)	393	27
Balance at December 31	\$ 1,314	\$ 1,308	\$ 799

* Includes components of comprehensive income, which are disclosed separately in the Consolidated Statement of Comprehensive Income.

Note 4

Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2013	2012	2011
Net (increase) decrease in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	\$ (1,101)	\$ 1,153	\$ (2,156)
Increase in inventories	(237)	(233)	(404)
Decrease (increase) in prepaid expenses and other current assets	834	(471)	(853)
Increase in accounts payable and accrued liabilities	160	544	3,839
(Decrease) increase in income and other taxes payable	(987)	(630)	1,892
Net (increase) decrease in operating working capital	\$ (1,331)	\$ 363	\$ 2,318
Net cash provided by operating activities includes the following cash payments for income taxes:			
Income taxes	\$ 12,898	\$ 17,334	\$ 17,374
Net sales (purchases) of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	\$ (7)	\$ (35)	\$ (112)
Marketable securities sold	10	32	38
Net sales (purchases) of marketable securities	\$ 3	\$ (3)	\$ (74)
Net sales (purchases) of time deposits consisted of the following gross amounts:			
Time deposits purchased	\$ (2,317)	\$ (717)	\$ (6,439)
Time deposits matured	3,017	3,967	5,335
Net sales (purchases) of time deposits	\$ 700	\$ 3,250	\$ (1,104)

The "Net (increase) decrease in operating working capital" includes reductions of \$79, \$98 and \$121 for excess income tax benefits associated with stock options exercised during 2013, 2012 and 2011, 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.

In February 2011, the company acquired Atlas Energy, Inc. (Atlas) for the aggregate purchase price of approximately \$4,500. The purchase price included assumption of debt and certain payments noted below. The "Acquisition of Atlas Energy" reflects the \$3,009 cash paid for all the common shares of Atlas. An "Advance to Atlas Energy" of \$403 was made to facilitate the purchase of a 49 percent interest in Laurel Mountain Midstream LLC on the day of closing. The "Repayments of long-term debt and other financing obligations" in 2011 includes \$761 for repayment of Atlas debt and \$271 for payoff of the Atlas revolving credit facility. The "Net (increase) decrease in operating working capital" includes \$184 for payments made in connection with Atlas equity awards subsequent to the acquisition. The remaining impacts of the acquisition did not have a material impact on the Consolidated Statement of Cash Flows.

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 \$5,004, \$5,004 and \$4,262 in 2013, 2012 and 2011, respectively. In 2013, 2012 and 2011, the company purchased 41.6 million, 46.6 million and 42.3 million common shares for \$5,000, \$5,000 and \$4,250 under its ongoing share repurchase program, respectively.

In 2013, 2012 and 2011, "Net sales (purchases) of other short-term investments" generally consisted of restricted cash associated with tax payments, upstream abandonment activities, funds held in escrow for asset acquisitions and capital investment projects 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 company issued \$374 in 2011 of tax exempt bonds as a source of funds for U.S. refinery projects, which is included in "Proceeds from issuance of long-term debt."

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 \$82 was received in 2013. "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 64, 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, 2013.

Note 4 Information Relating to the Consolidated Statement of Cash Flows - Continued

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		
	2013	2012	2011
Additions to properties, plant and equipment*	\$ 36,550	\$ 29,526	\$ 25,440
Additions to investments	934	1,042	900
Current-year dry hole expenditures	594	475	332
Payments for other liabilities and assets, net	(93)	(105)	(172)
Capital expenditures	37,985	30,938	26,500
Expensed exploration expenditures	1,178	1,173	839
Assets acquired through capital lease obligations and other financing obligations	16	1	32
Capital and exploratory expenditures, excluding equity affiliates	39,179	32,112	27,371
Company’s share of expenditures by equity affiliates	2,698	2,117	1,695
Capital and exploratory expenditures, including equity affiliates	\$ 41,877	\$ 34,229	\$ 29,066

*Excludes noncash additions of \$1,661 in 2013, \$4,569 in 2012 and \$945 in 2011.

Note 5

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.

During 2012, Chevron implemented legal reorganizations in which certain Chevron subsidiaries transferred assets to or under CUSA. The summarized financial information for CUSA and its consolidated subsidiaries presented in the following table gives retroactive effect to the reorganizations as if they had occurred on January 1, 2011. However, the financial information in the following table may not reflect the financial position and operating results in the periods presented if the reorganization had occurred on that date.

The summarized financial information for CUSA and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2013	2012	2011
Sales and other operating revenues	\$ 174,318	\$ 183,215	\$ 187,929
Total costs and other deductions	169,984	175,009	178,510
Net income attributable to CUSA	3,714	6,216	6,898

	At December 31	
	2013	2012
Current assets	\$ 17,626	\$ 18,983
Other assets	57,288	52,082
Current liabilities	17,486	18,161
Other liabilities	28,119	26,472
Total CUSA net equity	\$ 29,309	\$ 26,432

Memo: Total debt	\$ 14,482	\$ 14,482
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Note 6

Summarized Financial Data – Chevron Transport Corporation Ltd.

Chevron Transport Corporation Ltd. (CTC), incorporated in Bermuda, is an indirect, wholly owned subsidiary of Chevron Corporation. CTC is the principal operator of Chevron’s international tanker fleet and is engaged in the marine transportation of crude oil and refined petroleum products. Most of CTC’s shipping revenue is derived from providing transportation services to other Chevron companies. Chevron Corporation has fully and unconditionally guaranteed this subsidiary’s obligations in connection with certain debt securities issued by a third party. Summarized financial information for CTC and its consolidated subsidiaries is as follows:

	Year ended December 31		
	2013	2012	2011
Sales and other operating revenues	\$ 504	\$ 606	\$ 793
Total costs and other deductions	695	745	974
Net loss attributable to CTC	(191)	(135)	(177)

	At December 31	
	2013	2012
Current assets	\$ 221	\$ 199
Other assets	549	313
Current liabilities	94	154
Other liabilities	911	415
Total CTC net deficit	\$ (235)	\$ (57)

There were no restrictions on CTC’s ability to pay dividends or make loans or advances at December 31, 2013.

Note 7 Summarized Financial Data - Tengizchevroil LLP

Note 7

Summarized Financial Data – Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 12, on page 45, for a discussion of TCO operations.

Summarized financial information for 100 percent of TCO is presented in the following table:

	Year ended December 31		
	2013	2012	2011
Sales and other operating revenues	\$ 25,239	\$ 23,089	\$ 25,278
Costs and other deductions	11,173	10,064	10,941
Net income attributable to TCO	9,855	9,119	10,039

	At December 31	
	2013	2012
Current assets	\$ 3,598	\$ 3,251
Other assets	12,964	12,020
Current liabilities	3,016	2,597
Other liabilities	2,761	3,390
Total TCO net equity	\$ 10,785	\$ 9,284

Note 8

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	
	2013	2012
Upstream	\$ 445	\$ 433
Downstream	316	316
All Other	—	—
Total	761	749
Less: Accumulated amortization	523	479
Net capitalized leased assets	\$ 238	\$ 270

Rental expenses incurred for operating leases during 2013, 2012 and 2011 were as follows:

	Year ended December 31		
	2013	2012	2011
Minimum rentals	\$ 1,049	\$ 973	\$ 892
Contingent rentals	1	7	11
Total	1,050	980	903
Less: Sublease rental income	25	32	39
Net rental expense	\$ 1,025	\$ 948	\$ 864

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, 2013, the estimated future minimum lease payments (net of noncancelable sublease rentals) under operating and capital leases, which at inception had a non-cancelable term of more than one year, were as follows:

	At December 31	
	Operating Leases	Capital Leases
Year: 2014	\$ 798	\$ 45
2015	733	32
2016	594	20
2017	472	17
2018	306	17
Thereafter	806	46
Total	\$ 3,709	\$ 177
Less: Amounts representing interest and executory costs		\$ (37)
Net present values		140
Less: Capital lease obligations included in short-term debt		(43)
Long-term capital lease obligations		\$ 97

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 liability are described 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 below show the fair value hierarchy for assets and liabilities measured at fair value on a recurring and nonrecurring basis at December 31, 2013, and December 31, 2012.

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, 2013.

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 did not have any material long-lived assets measured at fair value on a nonrecurring basis to report in 2013 or 2012.

Investments and Advances The company did not have any material investments and advances measured at fair value on a nonrecurring basis to report in 2013 or 2012.

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 \$16,245 and \$20,939 at December 31, 2013, and December 31, 2012, respectively. The instruments held in “Time deposits” are bank time deposits with maturities greater than 90 days, and had carrying/fair values of \$8 and \$708 at December 31, 2013, and December 31, 2012, respectively. 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, 2013.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2013				At December 31, 2012			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Marketable securities	\$ 263	\$ 263	\$ –	\$ –	\$ 266	\$ 266	\$ –	\$ –
Derivatives	28	–	28	–	86	21	65	–
Total Assets at Fair Value	\$ 291	\$ 263	\$ 28	\$ –	\$ 352	\$ 287	\$ 65	\$ –
Derivatives	89	80	9	–	149	148	1	–
Total Liabilities at Fair Value	\$ 89	\$ 80	\$ 9	\$ –	\$ 149	\$ 148	\$ 1	\$ –

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 2013	Total	Level 1	Level 2	Level 3	Before-Tax Loss Year 2012
Properties, plant and equipment, net (held and used)	\$ 102	\$ –	\$ –	\$ 102	\$ 278	\$ 84	\$ –	\$ –	\$ 84	\$ 213
Properties, plant and equipment, net (held for sale)	69	–	69	–	104	16	–	–	16	17
Investments and advances	38	–	35	3	228	–	–	–	–	15
Total Nonrecurring Assets at Fair Value	\$ 209	\$ –	\$ 104	\$ 105	\$ 610	\$ 100	\$ –	\$ –	\$ 100	\$ 245

Note 9 Fair Value Measurements - Continued

“Cash and cash equivalents” do not include investments with a carrying/fair value of \$1,210 and \$1,454 at December 31, 2013, and December 31, 2012, respectively. At December 31, 2013, these investments are classified as Level 1 and include restricted funds related to tax payments and certain upstream abandonment activities which are reported in “Deferred charges and other assets” on the Consolidated Balance Sheet. Long-term debt of \$11,960 and \$6,086 at December 31, 2013, and December 31, 2012, had estimated fair values of \$12,267 and \$6,770, respectively. Long-term debt primarily includes corporate issued bonds. The fair value of corporate bonds is \$11,581 and classified as Level 1. The fair value of the other bonds is \$686 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, 2013 and 2012, 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, 2013, December 31, 2012, and December 31, 2011, 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 2013	At December 31 2012
Commodity	Accounts and notes receivable, net	\$ 22	\$ 57
Commodity	Long-term receivables, net	6	29
Total Assets at Fair Value		\$ 28	\$ 86
Commodity	Accounts payable	\$ 65	\$ 112
Commodity	Deferred credits and other noncurrent obligations	24	37
Total Liabilities at Fair Value		\$ 89	\$ 149

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		
		2013	2012	2011
Commodity	Sales and other operating revenues	\$ (108)	\$ (49)	\$ (255)
Commodity	Purchased crude oil and products	(77)	(24)	15
Commodity	Other income	(9)	6	(2)
		\$ (194)	\$ (67)	\$ (242)

The table below represents gross and net derivative assets and liabilities subject to netting agreements on the Consolidated Balance Sheet at December 31, 2013 and December 31, 2012.

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

	Gross Amount Recognized		Gross Amounts Offset		Net Amounts Presented		Gross Amounts Not Offset		Net Amount
At December 31, 2013									
Derivative Assets	\$	732	\$	704	\$	28	\$	27	\$ 1
Derivative Liabilities	\$	793	\$	704	\$	89	\$	—	\$ 89
At December 31, 2012									
Derivative Assets	\$	749	\$	663	\$	86	\$	64	\$ 22
Derivative Liabilities	\$	812	\$	663	\$	149	\$	5	\$ 144

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

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 project. 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 operations, power and energy services, worldwide cash management and debt financing activities, corporate administrative functions, insurance operations, real estate activities, alternative fuels, and technology companies.

The segments are separately managed for investment purposes under a structure that includes “segment managers” who report to the company’s “chief operating decision maker” (CODM). The CODM is the company’s Executive Committee (EXCOM), a committee of senior officers that includes the Chief Executive Officer, and EXCOM reports to the Board of Directors of Chevron Corporation.

The operating 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.

Segment managers for the reportable segments are directly accountable to and maintain regular contact with the company’s CODM to discuss the segment’s operating activities and financial performance. The CODM approves annual capital and exploratory budgets at the reportable segment level, as well as reviews capital and exploratory funding for major projects and approves major changes to the annual capital and

Note 11 Operating Segments and Geographic Data - Continued

exploratory budgets. However, business-unit managers within the operating segments are directly responsible for decisions relating to project implementation and all other matters connected with daily operations. Company officers who are members of the EXCOM also have individual management responsibilities and participate in other committees for purposes other than acting as the CODM.

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		
	2013	2012	2011
Segment Earnings			
Upstream			
United States	\$ 4,044	\$ 5,332	\$ 6,512
International	16,765	18,456	18,274
Total Upstream	20,809	23,788	24,786
Downstream			
United States	787	2,048	1,506
International	1,450	2,251	2,085
Total Downstream	2,237	4,299	3,591
Total Segment Earnings	23,046	28,087	28,377
All Other			
Interest income	80	83	78
Other	(1,703)	(1,991)	(1,560)
Net Income Attributable to Chevron Corporation	\$ 21,423	\$ 26,179	\$ 26,895

Segment Assets Segment assets do not include intercompany investments or intercompany receivables. Segment assets at year-end 2013 and 2012 are as follows:

	At December 31	
	2013	2012
Upstream		
United States	\$ 45,436	\$ 41,891
International	137,096	115,806
Goodwill	4,639	4,640
Total Upstream	187,171	162,337
Downstream		
United States	23,829	23,023
International	20,268	20,024
Total Downstream	44,097	43,047
Total Segment Assets	231,268	205,384
All Other		
United States	7,326	7,727
International	15,159	19,871
Total All Other	22,485	27,598
Total Assets – United States	76,591	72,641
Total Assets – International	172,523	155,701
Goodwill	4,639	4,640
Total Assets	\$ 253,753	\$ 232,982

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2013, 2012 and 2011, 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 from crude oil. This segment also generates revenues from the manufacture and sale of additives for fuels and lubricant oils and the transportation and trading of refined products, crude oil and natural gas liquids.

Note 11 Operating Segments and Geographic Data - Continued

	Year ended December 31		
	2013	2012	2011
Upstream			
United States	\$ 8,052	\$ 6,416	\$ 9,623
Intersegment	16,865	17,229	18,115
Total United States	24,917	23,645	27,738
International	17,607	19,459	20,086
Intersegment	33,034	34,094	35,012
Total International	50,641	53,553	55,098
Total Upstream	75,558	77,198	82,836
Downstream			
United States	80,272	83,043	86,793
Excise and similar taxes	4,792	4,665	4,199
Intersegment	39	49	86
Total United States	85,103	87,757	91,078
International	105,373	113,279	119,254
Excise and similar taxes	3,699	3,346	3,886
Intersegment	859	80	81
Total International	109,931	116,705	123,221
Total Downstream	195,034	204,462	214,299
All Other			
United States	358	378	526
Intersegment	1,524	1,300	1,072
Total United States	1,882	1,678	1,598
International	3	4	4
Intersegment	31	48	42
Total International	34	52	46
Total All Other	1,916	1,730	1,644
Segment Sales and Other			
Operating Revenues			
United States	111,902	113,080	120,414
International	160,606	170,310	178,365
Total Segment Sales and Other			
Operating Revenues	272,508	283,390	298,779
Elimination of intersegment sales	(52,352)	(52,800)	(54,408)
Total Sales and Other			
Operating Revenues	\$ 220,156	\$ 230,590	\$ 244,371

Segment Income Taxes Segment income tax expense for the years 2013, 2012 and 2011 is as follows:

	Year ended December 31		
	2013	2012	2011
Upstream			
United States	\$ 2,333	\$ 2,820	\$ 3,701
International	12,470	16,554	16,743
Total Upstream	14,803	19,374	20,444
Downstream			
United States	364	1,051	785
International	389	587	416
Total Downstream	753	1,638	1,201
All Other	(1,248)	(1,016)	(1,019)
Total Income Tax Expense	\$ 14,308	\$ 19,996	\$ 20,626

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 12. Information related to properties, plant and equipment by segment is contained in Note 13, on page 47.

Note 12

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		
	2013	2012	2013	2012	2011
Upstream					
Tengizchevroil	\$ 5,875	\$ 5,451	\$ 4,957	\$ 4,614	\$ 5,097
Petropiar	858	952	339	55	116
Caspian Pipeline Consortium	1,298	1,187	113	96	122
Petroboscan	1,375	1,261	300	229	247
Angola LNG Limited	3,423	3,186	(111)	(106)	(42)
Other	2,835	2,658	214	266	166
Total Upstream	15,664	14,695	5,812	5,154	5,706
Downstream					
GS Caltex Corporation	2,518	2,610	132	249	248
Chevron Phillips Chemical Company LLC	4,312	3,451	1,371	1,206	985
Star Petroleum Refining Company Ltd.	—	—	—	22	75
Caltex Australia Ltd.	1,020	835	224	77	117
Other	989	837	199	196	183
Total Downstream	8,839	7,733	1,926	1,750	1,608
All Other					
Other	375	640	(211)	(15)	49
Total equity method	\$ 24,878	\$ 23,068	\$ 7,527	\$ 6,889	\$ 7,363
Other at or below cost	624	650			
Total investments and advances	\$ 25,502	\$ 23,718			
Total United States	\$ 6,638	\$ 5,788	\$ 1,294	\$ 1,268	\$ 1,119
Total International	\$ 18,864	\$ 17,930	\$ 6,233	\$ 5,621	\$ 6,244

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 was formed in 1993 to develop the Tengiz and Korolev crude oil fields in Kazakhstan over a 40-year period. At December 31, 2013, the company's carrying value of its investment in TCO was about \$160 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 7, on page 40, for summarized financial information for 100 percent of TCO.

Note 12 Investment and Advances - Continued

Petropiar Chevron has a 30 percent interest in Petropiar, a joint stock company formed in 2008 to operate the Hamaca heavy-oil production and upgrading project. The project, located in Venezuela's Orinoco Belt, has a 25-year contract term. Prior to the formation of Petropiar, Chevron had a 30 percent interest in the Hamaca project. At December 31, 2013, the company's carrying value of its investment in Petropiar was approximately \$170 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 joined the consortium in 1997 and has investments and advances totaling \$1,298, which includes long-term loans of \$1,251 at year-end 2013. 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 percent interest in Petroboscan, a joint stock company formed in 2006 to operate the Boscan Field in Venezuela until 2026. Chevron previously operated the field under an operating service agreement. At December 31, 2013, the company's carrying value of its investment in Petroboscan was approximately \$180 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. In 2013, Chevron finalized a financial agreement with Petroboscan. The financing, not to exceed \$2 billion, will occur in stages over a limited draw-down period set to expire on December 31, 2018. The loan will support a specific work program to maintain and increase production to an agreed-upon level. The terms are designed to

support cash needs for ongoing operations and new development, as well as distributions.

Angola LNG Ltd. Chevron has a 36 percent interest in Angola LNG Ltd., 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 and petrochemicals, 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, 2013, the fair value of Chevron's share of CAL common stock was approximately \$2,400.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes \$14,635, \$17,356 and \$20,164 with affiliated companies for 2013, 2012 and 2011, respectively. "Purchased crude oil and products" includes \$7,063, \$6,634 and \$7,489 with affiliated companies for 2013, 2012 and 2011, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes \$1,328 and \$1,207 due from affiliated companies at December 31, 2013 and 2012, respectively. "Accounts payable" includes \$466 and \$407 due to affiliated companies at December 31, 2013 and 2012, 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 \$1,129, \$1,494 and \$957 at December 31, 2013, 2012 and 2011, respectively.

Year ended December 31	Affiliates			Chevron Share		
	2013	2012	2011	2013	2012	2011
Total revenues	\$ 131,875	\$136,065	\$ 140,107	\$ 63,101	\$ 65,196	\$ 68,632
Income before income tax expense	24,075	23,016	23,054	11,108	9,856	10,555
Net income attributable to affiliates	15,594	16,786	16,663	7,845	6,938	7,413
At December 31						
Current assets	\$ 39,713	\$ 37,541	\$ 35,573	\$ 15,156	\$ 14,732	\$ 14,695
Noncurrent assets	68,593	66,065	61,855	25,059	23,523	22,422
Current liabilities	29,642	27,878	24,671	11,587	11,093	11,040
Noncurrent liabilities	19,442	19,366	19,267	4,559	4,879	4,491
Total affiliates' net equity	\$ 59,222	\$ 56,362	\$ 53,490	\$ 24,069	\$ 22,283	\$ 21,586

Note 13 Properties, Plant and Equipment

Note 13

Properties, Plant and Equipment¹

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost ^{2,3}			Depreciation Expense ⁴		
	2013	2012	2011	2013	2012	2011	2013	2012	2011	2013	2012	2011
Upstream												
United States	\$ 89,555	\$ 81,908	\$ 74,369	\$ 41,831	\$ 37,909	\$ 33,461	\$ 8,188	\$ 8,211	\$ 14,404	\$ 4,412	\$ 3,902	\$ 3,870
International	169,623	145,799	125,795	104,100	85,318	72,543	27,383	21,343	15,722	8,336	8,015	7,590
Total Upstream	259,178	227,707	200,164	145,931	123,227	106,004	35,571	29,554	30,126	12,748	11,917	11,460
Downstream												
United States	22,407	21,792	20,699	11,481	11,333	10,723	1,154	1,498	1,226	780	799	776
International	9,303	8,990	7,422	4,139	3,930	2,995	653	2,544	443	360	308	332
Total Downstream	31,710	30,782	28,121	15,620	15,263	13,718	1,807	4,042	1,669	1,140	1,107	1,108
All Other⁵												
United States	5,402	4,959	5,117	3,194	2,845	2,872	721	415	591	286	384	338
International	143	33	30	84	13	14	23	4	5	12	5	5
Total All Other	5,545	4,992	5,147	3,278	2,858	2,886	744	419	596	298	389	343
Total United States	117,364	108,659	100,185	56,506	52,087	47,056	10,063	10,124	16,221	5,478	5,085	4,984
Total International	179,069	154,822	133,247	108,323	89,261	75,552	28,059	23,891	16,170	8,708	8,328	7,927
Total	\$ 296,433	\$ 263,481	\$ 233,432	\$ 164,829	\$ 141,348	\$ 122,608	\$ 38,122	\$ 34,015	\$ 32,391	\$ 14,186	\$ 13,413	\$ 12,911

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 2013.

Australia had \$31,464, \$21,770 and \$12,423 in 2013, 2012 and 2011, respectively. Nigeria had PP&E of \$18,429, \$17,485 and \$15,601 for 2013, 2012 and 2011, respectively.

² Net of dry hole expense related to prior years' expenditures of \$89, \$80 and \$45 in 2013, 2012 and 2011, respectively.

³ Includes properties acquired with the acquisition of Atlas Energy, Inc., in 2011.

⁴ Depreciation expense includes accretion expense of \$627, \$629 and \$628 in 2013, 2012 and 2011, respectively.

⁵ Primarily mining operations, power and energy services, real estate assets and management information systems.

Note 14

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 ten 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

Note 14 Litigation - Continued

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 a 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 on the next page. 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.

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 appealed the tribunal's award. 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 has 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 June 27, 2012, the Lago Agrio plaintiffs filed an action against Chevron Corporation in the Superior Court of Justice in Brasília, 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 14th, 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 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,

Note 14 Litigation - Continued

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 Tribunal has divided the merits phase of the proceedings 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 expects that the application of this ruling will be considered by the Tribunal in Phase Two, including a determination of 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 set a hearing on April 28-30, 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 plaintiff's 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 defendant's 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. Post-trial briefing has concluded, but no decision has been rendered by the Federal District Court as of the date of this report.

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 15

Taxes

Income Taxes

	Year ended December 31		
	2013	2012	2011
Taxes on income			
U.S. federal			
Current	\$ 15	\$ 1,703	\$ 1,893
Deferred	1,128	673	877
State and local			
Current	120	652	596
Deferred	74	(145)	41
Total United States	1,337	2,883	3,407
International			
Current	12,296	15,626	16,548
Deferred	675	1,487	671
Total International	12,971	17,113	17,219
Total taxes on income	\$ 14,308	\$ 19,996	\$ 20,626

In 2013, before-tax income for U.S. operations, including related corporate and other charges, was \$4,672, compared with before-tax income of \$8,456 and \$10,222 in 2012 and 2011, respectively. For international operations, before-tax income was \$31,233, \$37,876 and \$37,412 in 2013, 2012 and 2011, respectively. U.S. federal income tax expense was reduced by \$175, \$165 and \$191 in 2013, 2012 and 2011, 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		
	2013	2012	2011
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	5.1	7.8	7.5
State and local taxes on income, net of U.S. federal income tax benefit	0.6	0.6	0.9
Prior-year tax adjustments	(0.8)	(0.2)	(0.1)
Tax credits	(0.5)	(0.4)	(0.4)
Effects of changes in tax rates	—	0.3	0.5
Other	0.5	0.1	(0.1)
Effective tax rate	39.9%	43.2%	43.3%

The company's effective tax rate decreased from 43.2 percent in 2012 to 39.9 percent in 2013. The decrease was 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.

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	
	2013	2012
Deferred tax liabilities		
Properties, plant and equipment	\$ 25,936	\$ 24,295
Investments and other	2,272	2,276
Total deferred tax liabilities	28,208	26,571
Deferred tax assets		
Foreign tax credits	(11,572)	(10,817)
Abandonment/environmental reserves	(6,279)	(5,728)
Employee benefits	(3,825)	(5,100)
Deferred credits	(2,768)	(2,891)
Tax loss carryforwards	(1,016)	(738)
Other accrued liabilities	(533)	(381)
Inventory	(358)	(281)
Miscellaneous	(1,439)	(1,835)
Total deferred tax assets	(27,790)	(27,771)
Deferred tax assets valuation allowance	17,171	15,443
Total deferred taxes, net	\$ 17,589	\$ 14,243

Deferred tax liabilities at the end of 2013 increased by approximately \$1,600 from year-end 2012. The increase was related to increased temporary differences for property, plant and equipment. Deferred tax assets were essentially unchanged between periods.

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 2013, the company had tax loss carryforwards of approximately \$3,064 and tax credit carryforwards of approximately \$1,301 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 2014 through 2029. U.S. foreign tax credit carryforwards of \$11,572 will expire between 2014 and 2023.

Note 15 Taxes - Continued

At December 31, 2013 and 2012, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2013	2012
Prepaid expenses and other current assets	\$ (1,341)	\$ (1,365)
Deferred charges and other assets	(2,954)	(2,662)
Federal and other taxes on income	583	598
Noncurrent deferred income taxes	21,301	17,672
Total deferred income taxes, net	\$ 17,589	\$ 14,243

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 \$31,300 at December 31, 2013. 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 2013, 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, 2013, 2012 and 2011. 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.

	2013	2012	2011
Balance at January 1	\$ 3,071	\$ 3,481	\$ 3,507
Foreign currency effects	(58)	4	(2)
Additions based on tax positions taken in current year	276	543	469
Additions/reductions resulting from current-year asset acquisitions/sales	—	—	(41)
Additions for tax positions taken in prior years	1,164	152	236
Reductions for tax positions taken in prior years	(176)	(899)	(366)
Settlements with taxing authorities in current year	(320)	(138)	(318)
Reductions as a result of a lapse of the applicable statute of limitations	(109)	(72)	(4)
Balance at December 31	\$ 3,848	\$ 3,071	\$ 3,481

The increase in unrecognized tax benefits between December 31, 2012, and December 31, 2013 was primarily due to additions for refund claims to be filed with respect to prior years.

Approximately 71 percent of the \$3,848 of unrecognized tax benefits at December 31, 2013, 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, 2013. 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 – 2009 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.

The company completed its assessment of the potential impact of the August 2012 decision by the U.S. Court of Appeals for the Third Circuit that disallowed the Historic Rehabilitation Tax Credits claimed by an unrelated taxpayer. The findings of this assessment did not result in a material impact on the company's financial position, results of operations or cash flows.

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, 2013, accruals of \$215 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of \$293 as of year-end 2012. Income tax expense (benefit) associated with interest and penalties was \$(42), \$145 and \$(64) in 2013, 2012 and 2011, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2013	2012	2011
United States			
Excise and similar taxes on products and merchandise	\$ 4,792	\$ 4,665	\$ 4,199
Import duties and other levies	4	1	4
Property and other miscellaneous taxes	1,036	782	726
Payroll taxes	255	240	236
Taxes on production	333	328	308
Total United States	6,420	6,016	5,473
International			
Excise and similar taxes on products and merchandise	3,700	3,345	3,886
Import duties and other levies	41	106	3,511
Property and other miscellaneous taxes	2,486	2,501	2,354
Payroll taxes	168	160	148
Taxes on production	248	248	256
Total International	6,643	6,360	10,155
Total taxes other than on income	\$ 13,063	\$ 12,376	\$ 15,628

Note 16

Short-Term Debt

	At December 31	
	2013	2012
Commercial paper*	\$ 5,130	\$ 2,783
Notes payable to banks and others with originating terms of one year or less	49	23
Current maturities of long-term debt	—	20
Current maturities of long-term capital leases	34	38
Redeemable long-term obligations		
Long-term debt	3,152	3,151
Capital leases	9	12
Subtotal	8,374	6,027
Reclassified to long-term debt	(8,000)	(5,900)
Total short-term debt	\$ 374	\$ 127

*Weighted-average interest rates at December 31, 2013 and 2012, were 0.09 percent and 0.13 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, 2013, the company had no interest rate swaps on short-term debt.

At December 31, 2013, 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, 2013.

At December 31, 2013 and 2012, the company classified \$8,000 and \$5,900, respectively, of short-term debt as long-term. Settlement of these obligations is not expected to require the use of working capital within one year, as the company has both the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

Note 17 Long-Term Debt

Note 17

Long-Term Debt

Total long-term debt, excluding capital leases, at December 31, 2013, was \$19,960. The company's long-term debt outstanding at year-end 2013 and 2012 was as follows:

	At December 31	
	2013	2012
3.191% notes due 2023	\$ 2,250	\$ –
1.104% notes due 2017	2,000	2,000
1.718% notes due 2018	2,000	–
2.355% notes due 2022	2,000	2,000
4.95% notes due 2019	1,500	1,500
2.427% notes due 2020	1,000	–
0.889% notes due 2016	750	–
8.625% debentures due 2032	147	147
8.625% debentures due 2031	107	107
8% 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 (5.96%) ¹	38	38
7.5% debentures due 2043	–	83
7.327% amortizing notes due 2014 ²	–	23
7.327% amortizing notes due 2013 ²	–	20
Total including debt due within one year	11,960	6,086
Debt due within one year	–	(20)
Reclassified from short-term debt	8,000	5,900
Total long-term debt	\$ 19,960	\$ 11,966

¹ Weighted-average interest rate at December 31, 2013.

² Guarantee of ESOP debt.

Chevron has an automatic 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 \$11,960 matures as follows: 2014 – \$0; 2015 – \$0; 2016 – \$750; 2017 – \$2,000; 2018 – \$2,000; and after 2018 – \$7,210.

In June 2013, \$6,000 of Chevron Corporation bonds were issued, and \$83 of Texaco Capital, Inc. 7.5% bonds due 2043 and \$23 of Chevron Corporation 7.327% bonds due 2014 were redeemed early. In January 2013, \$20 of Chevron Corporation 7.327% bonds matured.

See Note 9, beginning on page 40, for information concerning the fair value of the company's long-term debt.

Note 18

New Accounting Standards

Income Taxes (Topic 740). Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (ASU 2013-11) In July 2013, the FASB issued ASU 2013-11, which became effective for the company January 1, 2014. The standard provides that a liability related to an unrecognized tax benefit should be offset against a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward if such settlement is required or expected in the event the uncertain tax position is disallowed. Adoption of the standard is not expected to have a significant effect on the company's results of operations, financial position or liquidity.

Note 19

Accounting for Suspended Exploratory Wells

The company continues to capitalize exploratory well cost 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 entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met or if an enterprise 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. (Note that an entity is not required to complete the exploratory well as a producing well.) The accounting standards provide a number of indicators that can assist an entity in demonstrating that sufficient progress is being made in assessing the reserves and economic viability of the project. The following table indicates the changes to the company's suspended exploratory well costs for the three years ended December 31, 2013:

	2013	2012	2011
Beginning balance at January 1	\$ 2,681	\$ 2,434	\$ 2,718
Additions to capitalized exploratory well costs pending the determination of proved reserves	885	595	652
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(290)	(244)	(828)
Capitalized exploratory well costs charged to expense	(31)	(49)	(45)
Other reductions*	–	(55)	(63)
Ending balance at December 31	\$ 3,245	\$ 2,681	\$ 2,434

*Represents property sales.

Note 19 Accounting for Suspended Exploratory Wells - Continued

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		
	2013	2012	2011
Exploratory well costs capitalized for a period of one year or less	\$ 641	\$ 501	\$ 557
Exploratory well costs capitalized for a period greater than one year	2,604	2,180	1,877
Balance at December 31	\$ 3,245	\$ 2,681	\$ 2,434
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	51	46	47

*Certain projects have multiple wells or fields or both.

Of the \$2,604 of exploratory well costs capitalized for more than one year at December 31, 2013, \$1,733 (22 projects) is related to projects that had drilling activities under way or firmly planned for the near future. The \$871 balance is related to 29 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 \$871 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) \$382 (six projects) – undergoing front-end engineering and design with final investment decision expected within three years; (b) \$47 (two projects) – development concept under review by government; (c) \$384 (nine projects) – development alternatives under review; (d) \$58 (twelve 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 connected with the projects. Approximately half of these decisions are expected to occur in the next three years.

The \$2,604 of suspended well costs capitalized for a period greater than one year as of December 31, 2013, represents 191 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
1997–2002	\$ 120	28
2003–2007	531	46
2008–2012	1,953	117
Total	\$ 2,604	191

<i>Aging based on drilling completion date of last suspended well in project:</i>	Amount	Number of projects
1999	\$ 8	1
2003–2008	347	10
2009–2013	2,249	40
Total	\$ 2,604	51

Note 20

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2013, 2012 and 2011 was \$292 (\$190 after tax), \$283 (\$184 after tax) and \$265 (\$172 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance units and restricted stock units was \$223 (\$145 after tax), \$177 (\$115 after tax) and \$214 (\$139 after tax) for 2013, 2012 and 2011, respectively. No significant stock-based compensation cost was capitalized at December 31, 2013, or December 31, 2012.

Cash received in payment for option exercises under all share-based payment arrangements for 2013, 2012 and 2011 was \$553, \$753 and \$948, respectively. Actual tax benefits realized for the tax deductions from option exercises were \$73, \$101 and \$121 for 2013, 2012 and 2011, respectively.

Cash paid to settle performance units and stock appreciation rights was \$186, \$123 and \$151 for 2013, 2012 and 2011, 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, 2013, the contractual terms vary between three years for the performance units and 10 years for the stock options and stock appreciation rights.

Note 20 Stock Options and Other Share-Based Compensation - Continued

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 2013, 2012 and 2011 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	2013	Year ended December 31	
		2012	2011
Stock Options			
Expected term in years ¹	6.0	6.0	6.2
Volatility ²	31.3%	31.7%	31.0%
Risk-free interest rate based on zero coupon U.S. treasury note	1.2%	1.1%	2.6%
Dividend yield	3.3%	3.2%	3.6%
Weighted-average fair value per option granted	\$ 24.48	\$ 23.35	\$ 21.24

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 2013 is presented below:

	Shares (Thousands)	Weighted- Average Exercise Price	Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at				
January 1, 2013	71,895	\$ 81.26		
Granted	13,194	\$ 116.45		
Exercised	(8,377)	\$ 68.20		
Forfeited	(1,086)	\$ 93.98		
Outstanding at				
December 31, 2013	75,626	\$ 88.44	6.12	\$ 2,758
Exercisable at				
December 31, 2013	51,797	\$ 78.52	5.05	\$ 2,403

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2013, 2012 and 2011 was \$445, \$580 and \$668, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2013, there was \$259 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, 2013, the number of LTIP performance units outstanding was equivalent to 2,827,757 shares. During 2013, 776,180 units were granted, 1,007,952 units vested with cash proceeds distributed to recipients and 64,715 units were forfeited. At December 31, 2013, units outstanding were 2,531,270, and the fair value of the liability recorded for these instruments was \$312 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 2.9 million equivalent shares as of December 31, 2013. A liability of \$107 was recorded for these awards.

Note 21

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.

Note 21 Employee Benefit Plans - Continued

The funded status of the company's pension and other postretirement benefit plans for 2013 and 2012 follows:

	Pension Benefits				Other Benefits	
	2013		2012		2013	2012
	U.S.	Int'l.	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	\$13,654	\$ 6,287	\$12,165	\$ 5,519	\$ 3,787	\$ 3,765
Service cost	495	197	452	181	66	61
Interest cost	471	314	435	320	149	153
Plan participants' contributions	—	8	—	7	154	151
Plan amendments	(78)	18	94	37	—	11
Actuarial (gain) loss	(1,398)	(206)	1,322	417	(636)	44
Foreign currency exchange rate changes	—	(187)	—	114	(23)	1
Benefits paid	(1,064)	(336)	(763)	(308)	(359)	(350)
Divestitures	—	—	(51)	—	—	(49)
Benefit obligation at December 31	12,080	6,095	13,654	6,287	3,138	3,787
Change in Plan Assets						
Fair value of plan assets at January 1	9,909	4,125	8,720	3,577	—	—
Actual return on plan assets	1,546	375	1,149	375	—	—
Foreign currency exchange rate changes	—	(21)	—	90	—	—
Employer contributions	819	392	844	384	205	199
Plan participants' contributions	—	8	—	7	154	151
Benefits paid	(1,064)	(336)	(763)	(308)	(359)	(350)
Divestitures	—	—	(41)	—	—	—
Fair value of plan assets at December 31	11,210	4,543	9,909	4,125	—	—
Funded Status at December 31	\$ (870)	\$ (1,552)	\$ (3,745)	\$ (2,162)	\$ (3,138)	\$ (3,787)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and other postretirement benefit plans at December 31, 2013 and 2012, include:

	Pension Benefits				Other Benefits	
	2013		2012		2013	2012
	U.S.	Int'l.	U.S.	Int'l.		
Deferred charges and other assets	\$ 394	\$ 128	\$ 7	\$ 55	\$ —	\$ —
Accrued liabilities	(76)	(81)	(61)	(76)	(215)	(225)
Noncurrent employee benefit plans	(1,188)	(1,599)	(3,691)	(2,141)	(2,923)	(3,562)
Net amount recognized at December 31	\$ (870)	\$ (1,552)	\$ (3,745)	\$ (2,162)	\$ (3,138)	\$ (3,787)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and OPEB plans were \$5,464 and \$9,742 at the end of 2013 and 2012, respectively. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2013		2012		2013	2012
	U.S.	Int'l.	U.S.	Int'l.		
Net actuarial loss	\$ 3,185	\$ 1,808	\$ 6,087	\$ 2,439	\$ 256	\$ 968
Prior service (credit) costs	(22)	167	58	170	70	20
Total recognized at December 31	\$ 3,163	\$ 1,975	\$ 6,145	\$ 2,609	\$ 326	\$ 988

The accumulated benefit obligations for all U.S. and international pension plans were \$10,876 and \$5,108, respectively, at December 31, 2013, and \$12,108 and \$5,167, respectively, at December 31, 2012.

Note 21 Employee Benefit Plans - Continued

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2013 and 2012, was:

	Pension Benefits			
	2013		2012	
	U.S.	Int'l.	U.S.	Int'l.
Projected benefit obligations	\$ 1,267	\$ 1,692	\$ 13,647	\$ 4,812
Accumulated benefit obligations	1,155	1,240	12,101	4,063
Fair value of plan assets	4	203	9,895	2,756

The components of net periodic benefit cost and amounts recognized in the Consolidated Statement of Comprehensive Income for 2013, 2012 and 2011 are shown in the table below:

	Pension Benefits						Other Benefits		
	2013		2012		2011		2013	2012	2011
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Net Periodic Benefit Cost									
Service cost	\$ 495	\$ 197	\$ 452	\$ 181	\$ 374	\$ 174	\$ 66	\$ 61	\$ 58
Interest cost	471	314	435	320	463	325	149	153	180
Expected return on plan assets	(701)	(274)	(634)	(269)	(613)	(283)	—	—	—
Amortization of prior service costs (credits)	2	21	(7)	18	(8)	19	(50)	(72)	(72)
Recognized actuarial losses	485	143	470	136	310	101	53	56	64
Settlement losses	173	12	220	5	298	—	—	(26)	—
Curtailement losses (gains)	—	—	—	—	—	35	—	—	(10)
Total net periodic benefit cost	925	413	936	391	824	371	218	172	220
Changes Recognized in Comprehensive Income									
Net actuarial (gain) loss during period	(2,244)	(476)	805	330	2,671	448	(659)	45	131
Amortization of actuarial loss	(658)	(155)	(700)	(141)	(608)	(101)	(53)	(79)	(64)
Prior service (credits) cost during period	(78)	18	94	37	—	27	—	11	—
Amortization of prior service (costs) credits	(2)	(21)	7	(18)	8	(54)	50	72	72
Total changes recognized in other comprehensive income	(2,982)	(634)	206	208	2,071	320	(662)	49	139
Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	\$ (2,057)	\$ (221)	\$ 1,142	\$ 599	\$ 2,895	\$ 691	\$ (444)	\$ 221	\$ 359

Net actuarial losses recorded in "Accumulated other comprehensive loss" at December 31, 2013, 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 10 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 2014, the company estimates actuarial losses of \$209, \$102 and \$7 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 \$132 will be recognized from "Accumulated other comprehensive loss" during 2014 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, 2013, was approximately 10 and 12 years for U.S. and international pension plans, respectively, and 10 years for other postretirement benefit plans. During 2014, the company estimates prior service (credits) costs of \$(9), \$21 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		
	2013		2012		2011		2013	2012	2011
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Assumptions used to determine benefit obligations:									
Discount rate	4.3%	5.8%	3.6%	5.2%	3.8%	5.9%	4.9%	4.1%	4.2%
Rate of compensation increase	4.5%	5.5%	4.5%	5.5%	4.5%	5.7%	N/A	N/A	N/A
Assumptions used to determine net periodic benefit cost:									
Discount rate	3.6%	5.2%	3.8%	5.9%	4.8%	6.5%	4.1%	4.2%	5.2%
Expected return on plan assets	7.5%	6.8%	7.5%	7.5%	7.8%	7.8%	N/A	N/A	N/A
Rate of compensation increase	4.5%	5.5%	4.5%	5.7%	4.5%	6.7%	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 2013, the company used an expected long-term rate of return of 7.5 percent for U.S. pension plan assets, which account for 71 percent of the company's pension plan assets. In 2012 and 2011, the company used a long-term rate of return of 7.5 and 7.8 percent 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, 2013, the company used a 4.3 percent discount rate for the U.S. pension plans and 4.7 percent for the main U.S. OPEB plan. The discount rates at the end of 2012 and 2011 were 3.6 and 3.9 percent and 3.8 and 4.0 percent for the U.S. pension plans and the main U.S. OPEB plans, respectively.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2013, for the main U.S. postretirement medical plan, the assumed health care cost-trend rates start with 7.3 percent in 2014 and gradually decline to 4.5 percent for 2025 and beyond. For this measurement at December 31, 2012, the assumed health care cost-trend rates started with 7.5 percent in 2013 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	\$ (11)
Effect on postretirement benefit obligation	\$ 137	\$ (115)

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

Note 21 Employee Benefit Plans - Continued

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 with estimated inputs entered into the model.

The fair value measurements of the company's pension plans for 2013 and 2012 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, 2012								
Equities								
U.S. ¹	\$ 1,709	\$ 1,709	\$ —	\$ —	\$ 334	\$ 334	\$ —	\$ —
International	1,263	1,263	—	—	520	520	—	—
Collective Trusts/Mutual Funds ²	2,979	7	2,972	—	1,233	402	831	—
Fixed Income								
Government	435	396	39	—	578	40	538	—
Corporate	384	—	384	—	230	25	175	30
Mortgage-Backed Securities	65	—	65	—	2	—	—	2
Other Asset Backed	51	—	51	—	4	—	4	—
Collective Trusts/Mutual Funds ²	1,520	—	1,520	—	671	26	645	—
Mixed Funds³								
	—	—	—	—	115	4	111	—
Real Estate⁴	1,114	—	—	1,114	177	—	—	177
Cash and Cash Equivalents	373	373	—	—	222	204	18	—
Other⁵	16	(44)	5	55	39	(3)	40	2
Total at December 31, 2012	\$ 9,909	\$ 3,704	\$ 5,036	\$1,169	\$ 4,125	\$ 1,552	\$ 2,362	\$ 211
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 Funds³								
	—	—	—	—	120	5	115	—
Real Estate⁴	1,265	—	—	1,265	294	—	—	294
Cash and Cash Equivalents	385	385	—	—	173	173	—	—
Other⁵	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

¹ U.S. equities include investments in the company's common stock in the amount of \$28 at December 31, 2013, and \$27 at December 31, 2012.

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:

	Corporate	Fixed Income Mortgage-Backed Securities	Real Estate	Other	Total
Total at December 31, 2011	\$ 27	\$ 2	\$ 998	\$ 56	\$ 1,083
Actual Return on Plan Assets:					
Assets held at the reporting date	—	—	108	1	109
Assets sold during the period	—	—	2	—	2
Purchases, Sales and Settlements	4	—	182	—	186
Transfers in and/or out of Level 3	—	—	—	—	—
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

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 88 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 40–60 percent, Fixed Income and Cash 25–50 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 2013, the company contributed \$819 and \$375 to its U.S. and international pension plans, respectively. In 2014, the company expects contributions to be approximately \$350 to

its U.S. plan and \$350 to its international 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 \$215 in 2014, compared with \$205 paid in 2013.

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.	
2014	\$ 1,212	\$ 284	\$ 215
2015	\$ 1,187	\$ 290	\$ 218
2016	\$ 1,170	\$ 284	\$ 221
2017	\$ 1,175	\$ 363	\$ 224
2018	\$ 1,168	\$ 391	\$ 227
2019–2023	\$ 5,399	\$ 2,307	\$ 1,148

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP).

Charges to expense for the ESIP represent the company's contributions to the plan, which are funded either through the purchase of shares of common stock on the open market or through the release of common stock held in the leveraged employee stock ownership plan (LESOP), which is described in the section that follows. Total company matching contributions to employee accounts within the ESIP were \$303, \$286 and \$263 in 2013, 2012 and 2011, respectively. This cost was reduced by the value of shares released from the LESOP totaling \$140, \$43 and \$38 in 2013, 2012 and 2011, respectively. The remaining amounts, totaling \$163, \$243

Note 21 Employee Benefit Plans – Continued

and \$225 in 2013, 2012 and 2011, respectively, represent open market purchases.

Employee Stock Ownership Plan Within the Chevron ESIP is an employee stock ownership plan (ESOP). In 1989, Chevron established a LESOP as a constituent part of the ESOP. The LESOP provides partial prefunding of the company's future commitments to the ESIP. The debt associated with the LESOP was retired in 2013 and the remaining unallocated shares were distributed to ESIP participants during the year.

The company reports compensation expense equal to LESOP debt principal repayments less dividends received and used by the LESOP for debt service. Interest accrued on LESOP debt was recorded as interest expense. Dividends paid on LESOP shares were reflected as a reduction of retained earnings. All LESOP shares were considered outstanding for earnings-per-share computations.

Total expense (credits) for the LESOP were \$5, \$1 and \$(1) in 2013, 2012 and 2011, respectively. The net expense (credit) for the respective years were composed of compensation expenses (credits) of \$4, \$(2) and \$(5) and charges to interest expense for LESOP debt of \$1, \$3 and \$4.

Of the dividends paid on the LESOP shares, \$38, \$18 and \$18 were used in 2013, 2012 and 2011, respectively, to service LESOP debt. The company also contributed \$7 and \$2 in 2013 and 2012, respectively, to satisfy LESOP debt service. No company contributions were required in 2011, as dividends received by the LESOP were sufficient to satisfy LESOP debt service.

Shares held in the LESOP were released and allocated to the accounts of ESIP participants based on debt service deemed to be paid in the year in proportion to the total of current-year and remaining debt service. LESOP shares as of December 31, 2013 and 2012, were as follows:

Thousands	2013	2012
Allocated shares	17,954	18,055
Unallocated shares	–	1,292
Total LESOP shares	17,954	19,347

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 2013, 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, 2013 and 2012, trust assets of \$40 and \$48, 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 \$871, \$898 and \$1,217 in 2013, 2012 and 2011, 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 20, beginning on page 55.

Note 22

Equity

Retained earnings at December 31, 2013 and 2012, included approximately \$11,395 and \$10,119, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2013, about 143 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 204,000 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 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 15, beginning on page 51, 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. As discussed on page 53, Chevron completed its assessment of the potential impact of the August 2012 decision by the U.S. Court of Appeals for the Third Circuit that disallowed the Historic Rehabilitation Tax Credits claimed by an unrelated taxpayer. The findings of this assessment did not result in a

material impact on the company's financial position, results of operations or cash flows.

Guarantees The company's guarantee of \$524 is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 14-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 other 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: 2014 – \$4,200; 2015 – \$4,500; 2016 – \$3,200; 2017 – \$2,600; 2018 – \$2,200; 2019 and after – \$6,900. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately \$3,600 in 2013, \$3,600 in 2012 and \$6,600 in 2011.

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, 2013, was \$1,456. Included in this balance were remediation activities at approximately 174 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 2013 was \$179. 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 2013 environmental reserves balance of \$1,277, \$834 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 \$443 was associated with various sites in international downstream \$79, upstream \$313 and other businesses \$51. Liabilities at all sites, whether operating, closed or divested, were primarily associated with the company's plans and activities to

Note 23 Other Contingencies and Commitments - Continued

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 2013 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. The revised and recirculated EIR is intended to comply with the appeals court decision. 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 2013, 2012 and 2011:

	2013	2012	2011
Balance at January 1	\$ 13,271	\$ 12,767	\$ 12,488
Liabilities incurred	59	133	62
Liabilities settled	(907)	(966)	(1,316)
Accretion expense	627	629	628
Revisions in estimated cash flows	1,248	708	905
Balance at December 31	\$ 14,298	\$ 13,271	\$ 12,767

In the table above, the amounts associated with "Revisions in estimated cash flows" reflect increasing cost estimates to abandon wells, equipment and facilities.

The long-term portion of the \$14,298 balance at the end of 2013 was \$13,476.

Note 25

Other Financial Information

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 2012 included after-tax gains of approximately \$2,800 relating to the sale of nonstrategic properties. Of this amount, approximately \$2,200 and \$600 related to upstream and downstream assets, respectively.

Other financial information is as follows:

	Year ended December 31		
	2013	2012	2011
Total financing interest and debt costs	\$ 284	\$ 242	\$ 288
Less: Capitalized interest	284	242	288
Interest and debt expense	\$ –	\$ –	\$ –
Research and development expenses	\$ 750	\$ 648	\$ 627
Foreign currency effects*	\$ 474	\$ (454)	\$ 121

*Includes \$244, \$(202) and \$(27) in 2013, 2012 and 2011, respectively, for the company's share of equity affiliates' foreign currency effects.

The excess of replacement cost over the carrying value of inventories for which the last-in, first-out (LIFO) method is used was \$9,150, and \$9,292 at December 31, 2013 and 2012, respectively. Replacement cost is generally based on average acquisition costs for the year. LIFO profits (charges) of \$14, \$121 and \$193 were included in earnings for the years 2013, 2012 and 2011, respectively.

The company has \$4,639 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 2013 and concluded no impairment was necessary.

Note 26

Assets Held for Sale

At December 31, 2013, the company classified \$580 of net properties, plant and equipment as "Assets Held for Sale" on the Consolidated Balance Sheet. These assets are associated with upstream operations that are anticipated to be sold in 2014. The revenues and earnings contributions of these assets in 2013 were not material.

Note 27

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 20, "Stock Options and Other Share-Based Compensation," beginning on page 55). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2013	2012	2011
Basic EPS Calculation			
Earnings available to common stockholders – Basic*	\$ 21,423	\$ 26,179	\$ 26,895
Weighted-average number of common shares outstanding	1,916	1,950	1,986
Add: Deferred awards held as stock units	1	–	–
Total weighted-average number of common shares outstanding	1,917	1,950	1,986
Earnings per share of common stock – Basic	\$ 11.18	\$ 13.42	\$ 13.54
Diluted EPS Calculation			
Earnings available to common stockholders – Diluted*	\$ 21,423	\$ 26,179	\$ 26,895
Weighted-average number of common shares outstanding	1,916	1,950	1,986
Add: Deferred awards held as stock units	1	–	–
Add: Dilutive effect of employee stock-based awards	15	15	15
Total weighted-average number of common shares outstanding	1,932	1,965	2,001
Earnings per share of common stock – Diluted	\$ 11.09	\$ 13.32	\$ 13.44

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

Five-Year Financial Summary

Unaudited

Millions of dollars, except per-share amounts

	2013	2012	2011	2010	2009
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues*	\$ 220,156	\$ 230,590	\$ 244,371	\$ 198,198	\$ 167,402
Income from equity affiliates and other income	8,692	11,319	9,335	6,730	4,234
Total Revenues and Other Income	228,848	241,909	253,706	204,928	171,636
Total Costs and Other Deductions	192,943	195,577	206,072	172,873	153,108
Income Before Income Tax Expense	35,905	46,332	47,634	32,055	18,528
Income Tax Expense	14,308	19,996	20,626	12,919	7,965
Net Income	21,597	26,336	27,008	19,136	10,563
Less: Net income attributable to noncontrolling interests	174	157	113	112	80
Net Income Attributable to Chevron Corporation	\$ 21,423	\$ 26,179	\$ 26,895	\$ 19,024	\$ 10,483
Per Share of Common Stock					
Net Income Attributable to Chevron					
– Basic	\$ 11.18	\$ 13.42	\$ 13.54	\$ 9.53	\$ 5.26
– Diluted	\$ 11.09	\$ 13.32	\$ 13.44	\$ 9.48	\$ 5.24
Cash Dividends Per Share	\$ 3.90	\$ 3.51	\$ 3.09	\$ 2.84	\$ 2.66
Balance Sheet Data (at December 31)					
Current assets	\$ 50,250	\$ 55,720	\$ 53,234	\$ 48,841	\$ 37,216
Noncurrent assets	203,503	177,262	156,240	135,928	127,405
Total Assets	253,753	232,982	209,474	184,769	164,621
Short-term debt	374	127	340	187	384
Other current liabilities	32,644	34,085	33,260	28,825	25,827
Long-term debt and capital lease obligations	20,057	12,065	9,812	11,289	10,130
Other noncurrent liabilities	50,251	48,873	43,881	38,657	35,719
Total Liabilities	103,326	95,150	87,293	78,958	72,060
Total Chevron Corporation Stockholders' Equity	\$ 149,113	\$ 136,524	\$ 121,382	\$ 105,081	\$ 91,914
Noncontrolling interests	1,314	1,308	799	730	647
Total Equity	\$ 150,427	\$ 137,832	\$ 122,181	\$ 105,811	\$ 92,561
*Includes excise, value-added and similar taxes:	\$ 8,492	\$ 8,010	\$ 8,085	\$ 8,591	\$ 8,109

Five-Year Operating Summary

Unaudited

Worldwide – Includes Equity in Affiliates

Thousands of barrels per day, except natural gas data,
which is millions of cubic feet per day

	2013	2012	2011	2010	2009
United States					
Net production of crude oil and natural gas liquids	449	455	465	489	484
Net production of natural gas ¹	1,246	1,203	1,279	1,314	1,399
Net oil-equivalent production	657	655	678	708	717
Refinery input	774	833	854	890	899
Sales of refined products	1,182	1,211	1,257	1,349	1,403
Sales of natural gas liquids	142	157	161	161	161
Total sales of petroleum products	1,324	1,368	1,418	1,510	1,564
Sales of natural gas	5,483	5,470	5,836	5,932	5,901
International					
Net production of crude oil and natural gas liquids ²	1,282	1,309	1,384	1,434	1,362
Other produced volumes ³	–	–	–	–	26
Net production of natural gas ¹	3,946	3,871	3,662	3,726	3,590
Net oil-equivalent production	1,940	1,955	1,995	2,055	1,987
Refinery input ⁴	864	869	933	1,004	979
Sales of refined products ⁵	1,529	1,554	1,692	1,764	1,851
Sales of natural gas liquids	88	88	87	105	111
Total sales of petroleum products	1,617	1,642	1,779	1,869	1,962
Sales of natural gas	4,251	4,315	4,361	4,493	4,062
Total Worldwide					
Net production of crude oil and natural gas liquids	1,731	1,764	1,849	1,923	1,846
Other produced volumes	–	–	–	–	26
Net production of natural gas ¹	5,192	5,074	4,941	5,040	4,989
Net oil-equivalent production	2,597	2,610	2,673	2,763	2,704
Refinery input ⁴	1,638	1,702	1,787	1,894	1,878
Sales of refined products ⁵	2,711	2,765	2,949	3,113	3,254
Sales of natural gas liquids	230	245	248	266	272
Total sales of petroleum products	2,941	3,010	3,197	3,379	3,526
Sales of natural gas	9,734	9,785	10,197	10,425	9,963
Worldwide – Excludes Equity in Affiliates					
Number of wells completed (net) ⁶					
Oil and gas	1,833	1,618	1,551	1,160	1,265
Dry ⁷	20	19	19	31	24
Productive oil and gas wells (net) ⁶	56,635	55,812	55,049	51,677	51,326

¹ Includes natural gas consumed in operations:

United States ⁷	72	65	69	62	58
International ⁷	452	457	447	475	463
Total ⁷	524	522	516	537	521

² Includes: Canada-synthetic oil
Venezuela affiliate-synthetic oil

³ Includes: Canada oil sands

⁴ 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.

⁵ Includes sales of affiliates (MBPD):

⁶ Net wells include wholly owned and the sum of fractional interests in partially owned wells.

⁷ 2012 and 2011 conform to 2013 presentation.

Supplemental Information on Oil and Gas Producing Activities

Unaudited

In accordance with FASB and SEC disclosure and reporting 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

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	Europe	Total	TCO	Other
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, 2012⁵									
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
Year Ended December 31, 2011									
Exploration									
Wells	\$ 321	\$ 71	\$ 104	\$ 146	\$ 242	\$ 188	\$ 1,072	\$ –	\$ –
Geological and geophysical	76	59	65	121	23	43	387	–	–
Rentals and other	109	45	83	67	71	78	453	–	–
Total exploration	506	175	252	334	336	309	1,912	–	–
Property acquisitions ²									
Proved	1,174	16	–	1	–	–	1,191	–	–
Unproved	7,404	228	–	–	–	25	7,657	–	–
Total property acquisitions	8,578	244	–	1	–	25	8,848	–	–
Development ³	5,517	1,537	2,698	2,867	2,638	633	15,890	379	368
Total Costs Incurred	\$ 14,601	\$ 1,956	\$ 2,950	\$ 3,202	\$ 2,974	\$ 967	\$ 26,650	\$ 379	\$ 368

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 64.

² Does not include properties acquired in nonmonetary transactions.

³ Includes \$661, \$963 and \$1,035 costs incurred prior to assignment of proved reserves for consolidated companies in 2013, 2012 and 2011 respectively.

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

	2013	2012 ⁵	
Total cost incurred	\$ 33.5	\$ 26.1	
Non-oil and gas activities	5.8	5.0	(Primarily includes LNG, gas-to-liquids and transportation activities)
ARO	(1.4)	(0.7)	
Upstream C&E	\$ 37.9	\$ 30.4	Reference page 20 Upstream total

⁵ 2012 Non-oil and gas allocation revised.

Table I Costs Incurred in Exploration,
Property Acquisitions and Development - Continued

on the company's estimated net proved-reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves and changes in estimated discounted future net cash flows. The Africa geographic area includes activities principally in Angola, Chad, Democratic Republic of the Congo, Nigeria and Republic of the Congo. The Asia geographic area includes activities principally in Azerbaijan, Bangladesh, China, Indonesia, Kazakhstan, Myanmar, the Partitioned Zone between Kuwait and Saudi Arabia, the Philippines, and Thailand. The Europe geographic area includes activities primarily in Denmark, the

Netherlands, Norway and the United Kingdom. The Other Americas geographic region includes activities primarily in Argentina, Brazil, Canada, Colombia, and Trinidad and Tobago. Amounts for TCO represent Chevron's 50 percent equity share of Tengizchevroil, an exploration and production partnership in the Republic of Kazakhstan. The affiliated companies Other amounts are composed of the company's equity interests principally in Venezuela and Angola. Refer to Note 12, beginning on page 45, 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	Europe	Total	TCO	Other
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	18,501	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

^{*} 2012 Non-oil and gas allocations revised.

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

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
At December 31, 2011									
Unproved properties	\$ 9,806	\$ 1,417	\$ 368	\$ 2,408	\$ 6	\$ 33	\$ 14,038	\$ 109	\$ –
Proved properties and related producing assets	57,674	11,029	25,549	36,740	2,244	9,549	142,785	6,583	1,607
Support equipment	1,071	292	1,362	1,544	533	169	4,971	1,018	–
Deferred exploratory wells	565	63	629	260	709	208	2,434	–	–
Other uncompleted projects	4,887	2,408	4,773	3,109	6,076	492	21,745	605	1,466
Gross Capitalized Costs	74,003	15,209	32,681	44,061	9,568	10,451	185,973	8,315	3,073
Unproved properties valuation	1,085	498	178	262	2	13	2,038	38	–
Proved producing properties – Depreciation and depletion	39,210	4,826	13,173	20,991	1,574	7,742	87,516	1,910	436
Support equipment depreciation	530	175	715	1,192	238	129	2,979	451	–
Accumulated provisions	40,825	5,499	14,066	22,445	1,814	7,884	92,533	2,399	436
Net Capitalized Costs	\$ 33,178	\$ 9,710	\$ 18,615	\$ 21,616	\$ 7,754	\$ 2,567	\$ 93,440	\$ 5,916	\$ 2,637

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 2013, 2012 and 2011 are shown in the following table. Net income from exploration and production activities as reported on page 44 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 44.

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

<i>Millions of dollars</i>	Consolidated Companies							Affiliated Companies	
	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other
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
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 64.

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

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	Europe	Total	TCO	Other
Year Ended December 31, 2011									
Revenues from net production									
Sales	\$ 2,508	\$ 2,047	\$ 1,174	\$ 9,431	\$ 1,474	\$ 1,868	\$ 18,502	\$ 8,581	\$ 1,988
Transfers	15,811	2,624	15,726	8,962	1,012	2,672	46,807	—	—
Total	18,319	4,671	16,900	18,393	2,486	4,540	65,309	8,581	1,988
Production expenses excluding taxes	(3,668)	(1,061)	(1,526)	(4,489)	(117)	(564)	(11,425)	(449)	(235)
Taxes other than on income	(597)	(137)	(153)	(242)	(396)	(2)	(1,527)	(429)	(815)
Proved producing properties:									
Depreciation and depletion	(3,366)	(796)	(2,225)	(2,923)	(136)	(580)	(10,026)	(442)	(140)
Accretion expense ²	(291)	(27)	(106)	(81)	(18)	(39)	(562)	(8)	(4)
Exploration expenses	(207)	(144)	(188)	(271)	(128)	(277)	(1,215)	—	—
Unproved properties valuation	(134)	(146)	(27)	(60)	—	(14)	(381)	—	—
Other income (expense) ³	163	(466)	(409)	231	(18)	(74)	(573)	(8)	(29)
Results before income taxes	10,219	1,894	12,266	10,558	1,673	2,990	39,600	7,245	765
Income tax expense	(3,728)	(535)	(7,802)	(5,374)	(507)	(1,913)	(19,859)	(2,176)	(392)
Results of Producing Operations	\$ 6,491	\$ 1,359	\$ 4,464	\$ 5,184	\$ 1,166	\$ 1,077	\$ 19,741	\$ 5,069	\$ 373

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 64.

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	Europe	Total	TCO	Other
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
Year Ended December 31, 2011									
Average sales prices									
Liquids, per barrel	\$ 97.51	\$ 89.87	\$ 109.45	\$ 100.55	\$ 103.70	\$ 107.11	\$ 101.63	\$ 94.60	\$ 90.90
Natural gas, per thousand cubic feet	4.02	2.97	0.41	5.28	9.98	9.91	5.29	1.60	6.57
Average production costs, per barrel ²	15.08	14.62	9.48	17.47	3.41	11.44	13.98	4.23	10.54

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**Table V** Reserve Quantity Information

Summary of Net Oil and Gas Reserves

	2013			2012			2011		
<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.	976	—	2,632	1,012	—	2,574	990	—	2,486
Other Americas	109	403	943	91	391	1,063	82	403	1,147
Africa	763	—	1,161	782	—	1,163	792	—	1,276
Asia	601	—	4,620	643	—	4,511	703	—	4,300
Australia	44	—	1,251	31	—	682	39	—	813
Europe	94	—	200	103	—	191	116	—	204
Total Consolidated	2,587	403	10,807	2,662	391	10,184	2,722	403	10,226
Affiliated Companies									
TCO	884	—	1,188	977	—	1,261	1,019	—	1,400
Other	105	44	330	115	50	377	93	50	75
Total Consolidated and Affiliated Companies	3,576	447	12,325	3,754	441	11,822	3,834	453	11,701
Proved Undeveloped									
Consolidated Companies									
U.S.	354	—	1,358	347	—	1,148	321	—	1,160
Other Americas	134	134	357	132	122	412	31	120	517
Africa	341	—	1,884	348	—	1,918	363	—	1,920
Asia	191	—	2,125	194	—	2,356	191	—	2,421
Australia	87	—	9,076	103	—	9,570	101	—	8,931
Europe	72	—	63	54	—	66	43	—	54
Total Consolidated	1,179	134	14,863	1,178	122	15,470	1,050	120	15,003
Affiliated Companies									
TCO	784	—	1,102	755	—	1,038	740	—	851
Other	49	176	856	49	182	865	64	194	1,128
Total Consolidated and Affiliated Companies	2,012	310	16,821	1,982	304	17,373	1,854	314	16,982
Total Proved Reserves	5,588	757	29,146	5,736	745	29,195	5,688	767	28,683

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 2013, 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 Reserve Quantities At the end of 2013, proved undeveloped reserves totaled 5.1 billion barrels of oil-equivalent (BOE), a decrease of 56 million BOE from year-end 2012. The decrease was due to the transfer of 461 million BOE to proved developed, partially offset by increases of 210 BOE in extensions and discoveries, 7 million BOE in purchases, 42 million BOE in improved recovery and 146 million BOE in revisions.

Investment to Convert Proved Undeveloped to Proved Developed Reserves

During 2013, investments totaling approximately \$17.4 billion in oil and gas producing activities and about \$3.4 billion in non-oil and gas producing activities were expended to advance the development of proved undeveloped reserves. Australia accounted for \$9.6 billion of the total, mainly for development and construction activities at the Gorgon and Wheatstone LNG projects. Expenditures of about \$3.5 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 \$3.0 billion, primarily related to development projects in Thailand, Indonesia and with the TCO affiliate in Kazakhstan. In Africa, another \$2.9 billion was expended on various offshore development and natural gas projects in Nigeria and Angola.

Proved Undeveloped Reserves for Five Years or More

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.

Table V Reserve Quantity Information - Continued

At year-end 2013, the company held approximately 1.6 billion BOE of proved undeveloped reserves that have remained undeveloped for five years or more. The reserves are held by consolidated and affiliated companies and the majority of these reserves are in locations where the company has a proven track record of developing major projects.

In Africa, the majority of the approximately 300 million BOE of proved undeveloped reserves that have remained undeveloped for five years or more is related to deepwater and natural gas developments in Nigeria. Major Nigerian deepwater development projects include Agbami, which started production in 2008 and has ongoing development activities to maintain full utilization of infrastructure capacity, and the Usan development, which started production in 2012. Also in Nigeria, various fields and infrastructure associated with the Escravos gas projects are currently under development.

In Asia, less than 200 million BOE remain classified as proved undeveloped for more than five years. The majority relate to ongoing development activities in the Pattani Field in Thailand and the Azeri-Chirag-Gunashli fields in Azerbaijan.

Affiliates account for 1.1 billion barrels 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. In Venezuela, development drilling continues at Hamaca to optimize utilization of upgrader capacity.

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 2013, 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 At December 31, 2013, proved reserves for the company were 11.2 billion BOE. Approximately 18 percent of the total reserves were located in the United States.

Aside from the TCO affiliate's Tengiz Field in Kazakhstan, no single property accounted for more than 5 percent of the company's total oil-equivalent proved reserves. About 18 other individual properties in the company's portfolio of assets each contained between 1 percent and 5 percent of the company's oil-equivalent proved reserves, which in the aggregate accounted for 44 percent of the company's total oil-equivalent proved reserves. These properties were geographically dispersed, located in the United States, Canada, South America, Africa, Asia and Australia.

In the United States, total proved reserves at year-end 2013 were 2.0 billion BOE. California properties accounted for 30 percent of the U.S. reserves, with most classified as heavy oil. Because of heavy oil's high viscosity and the need to employ enhanced recovery methods, most of the company's heavy oil fields in California employ a continuous steamflooding process. The Gulf of Mexico region contains 26 percent of the U.S. reserves and production operations are mostly offshore. Other U.S. areas represent the remaining 44 percent of U.S. reserves. For production of crude oil, some fields utilize enhanced recovery methods, including waterflooding and CO₂ injection.

For the three years ending December 31, 2013, 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, among other things, 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.

The company's estimated net proved reserves of crude oil, condensate, natural gas liquids and synthetic oil and changes thereto for the years 2011, 2012 and 2013 are shown in the table on page 76. The company's estimated net proved reserves of natural gas are shown on page 77.

Table V Reserve Quantity Information - Continued**Net Proved Reserves (Developed and Undeveloped) of Crude Oil, Condensate, Natural Gas Liquids and Synthetic Oil**

<i>Millions of barrels</i>	Consolidated Companies								Affiliated Companies			Total Consolidated and Affiliated Companies
	U.S.	Other Americas ¹	Africa	Asia	Australia	Europe	Synthetic Oil ²	Total	TCO	Synthetic Oil	Other ³	
Reserves at January 1, 2011	1,275	108	1,168	1,013	88	152	466	4,270	1,820	256	157	6,503
Changes attributable to:												
Revisions	63	4	60	25	(2)	15	32	197	28	—	10	235
Improved recovery	6	4	48	—	—	—	—	58	—	—	—	58
Extensions and discoveries	140	30	34	4	65	26	—	299	—	—	—	299
Purchases	2	—	—	—	—	—	40	42	—	—	—	42
Sales	(5)	—	—	—	(1)	—	—	(6)	—	—	—	(6)
Production	(170)	(33)	(155)	(148)	(10)	(34)	(15)	(565)	(89)	(12)	(10)	(676)
Reserves at December 31, 2011⁴	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

¹ Ending reserve balances in North America were 141, 121 and 13 and in South America were 102, 102 and 100 in 2013, 2012 and 2011, respectively.

² Reserves associated with Canada.

³ Ending reserve balances in Africa were 37, 41 and 38 and in South America were 117, 123 and 119 in 2013, 2012 and 2011, respectively.

⁴ Included are year-end reserve quantities related to production-sharing contracts (PSC). PSC-related reserve quantities are 20 percent, 20 percent and 22 percent for consolidated companies for 2013, 2012 and 2011, respectively.

Noteworthy amounts in the categories of liquids proved reserve changes for 2011 through 2013 are discussed below:

Revisions In 2011, net revisions increased reserves 235 million barrels. For consolidated companies, improved reservoir performance accounted for a majority of the 63 million barrel increase in the United States. In Africa, improved field performance drove the 60 million barrel increase. In Asia, increases from improved reservoir performance were partially offset by the effects of higher prices on entitlement volumes. Synthetic oil reserves in Canada increased by 32 million barrels, primarily due to geotechnical revisions. For affiliated companies, improved facility and reservoir performance was partially offset by the price effect on entitlement volumes at TCO.

In 2012, net revisions increased reserves 390 million barrels. 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, net revisions increased reserves 354 million barrels. 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.

Improved Recovery In 2011, improved recovery increased volumes by 58 million barrels. Reserves in Africa increased 48 million barrels due primarily to secondary recovery performance in Nigeria.

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.

Table V Reserve Quantity Information - Continued

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.

Extensions and Discoveries In 2011, extensions and discoveries increased reserves 299 million barrels. In the United States, additions related to two Gulf of Mexico projects resulted in the majority of the 140 million barrel increase. In Australia, the Wheatstone Project increased liquid volumes 65 million barrels. Africa and Other Americas increased reserves 34 million and 30 million barrels, respectively, following the start of new projects in these areas. In Europe, a project in the United Kingdom increased reserves 26 million barrels.

In 2012, extensions and discoveries increased reserves 218 million barrels. In Other Americas, extensions and discoveries increased reserves 101 million barrels, 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 activity in the mid-continent region were primarily responsible for the 77 million barrel increase.

In 2013, extensions and discoveries increased reserves 78 million barrels. In the United States, extensions and discoveries in the Midland and Delaware basins were primarily responsible for the 55 million barrel increase.

Purchases In 2011, purchases increased worldwide liquid volumes 42 million barrels. The acquisition of additional acreage in Canada increased synthetic oil reserves 40 million barrels.

Net Proved Reserves of Natural Gas

<i>Billions of cubic feet (BCF)</i>	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated Companies
	U.S.	Other Americas ¹	Africa	Asia	Australia	Europe	Total	TCO	Other ²	
Reserves at January 1, 2011	2,472	1,815	2,944	7,193	6,056	275	20,755	2,386	1,110	24,251
Changes attributable to:										
Revisions	217	(4)	39	196	(107)	74	415	(21)	103	497
Improved recovery	—	1	—	—	—	—	1	—	—	1
Extensions and discoveries	287	13	290	46	4,035	9	4,680	—	—	4,680
Purchases	1,231	—	—	2	—	—	1,233	—	—	1,233
Sales	(95)	—	—	(2)	(77)	—	(174)	—	—	(174)
Production ³	(466)	(161)	(77)	(714)	(163)	(100)	(1,681)	(114)	(10)	(1,805)
Reserves at December 31, 2011⁴	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, 2012⁴	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, 2013⁴	3,990	1,300	3,045	6,745	10,327	263	25,670	2,290	1,186	29,146

¹ Ending reserve balances in North America and South America were 54, 49, 19 and 1,246, 1,426, 1,645 in 2013, 2012 and 2011, respectively.

² Ending reserve balances in Africa and South America were 1,009, 1,068, 1,016 and 177, 174, 187 in 2013, 2012 and 2011, respectively.

³ Total "as sold" volumes are 1,704 BCF, 1,666 BCF and 1,615 BCF for 2013, 2012 and 2011, respectively. 2011 and 2012 conformed to 2013 presentation.

⁴ Includes reserve quantities related to production-sharing contracts (PSC). PSC-related reserve quantities are 20 percent, 21 percent and 21 percent for consolidated companies for 2013, 2012 and 2011, respectively.

Table V Reserve Quantity Information - Continued

Noteworthy amounts in the categories of natural gas proved-reserve changes for 2011 through 2013 are discussed below:

Revisions In 2011, net revisions increased reserves 497 BCF. For consolidated companies, improved reservoir performance accounted for a majority of the 217 BCF increase in the United States. In Asia, a net increase of 196 BCF was driven by development drilling and improved field performance in Thailand, partially offset by the effects of higher prices on entitlement volumes in Kazakhstan. For affiliated companies, ongoing reservoir assessment resulted in the recognition of additional reserves related to the Angola LNG project. At TCO, improved facility and reservoir performance was more than offset by the price effect on entitlement volumes.

In 2012, net revisions increased reserves 1,855 BCF. A net increase of 1,007 BCF in Asia was 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 increased reserves 718 BCF. A net increase of 627 BCF in Asia was 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.

Extensions and Discoveries In 2011, extensions and discoveries increased reserves 4,680 BCF. In Australia, the Wheatstone Project accounted for the 4,035 BCF in additions. In Africa, the start of a new natural gas development project in Nigeria resulted in the 290 BCF increase. In the United States, development drilling accounted for the majority of the 287 BCF increase.

In 2012, extensions and discoveries increased reserves by 1,011 BCF. The increase of 747 BCF in Australia was primarily related to positive drilling results at the Gorgon Project.

In 2013, extensions and discoveries increased reserves by 1,021 BCF, with the majority in the Appalachian region in the U.S.

Purchases In 2011, purchases increased reserves 1,233 BCF. In the United States, acquisitions in the Marcellus Shale increased reserves 1,230 BCF.

Sales In 2011, sales decreased reserves 174 BCF. In Australia, the Wheatstone Project unitization and equity sales agreements reduced reserves 77 BCF. In the United States, sales in Alaska and other smaller fields reduced reserves 95 BCF.

In 2012, sales decreased reserves by 538 BCF. Sales of a portion of the company's equity interest in the Wheatstone Project were responsible for the 439 BCF reserves 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, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of the FASB. Estimated future cash inflows from production are computed by applying 12-month average prices for oil and gas to year-end quantities of estimated net proved reserves. Future price changes are limited to those provided by contractual arrangements in existence at the end of each reporting year. Future development and production costs are those estimated future expenditures necessary to develop and produce year-end estimated proved reserves based on year-end cost indices, assuming continuation of year-end economic conditions, and include estimated costs for asset retirement obligations. Estimated future income taxes are calculated by applying appropriate year-end statutory tax rates. These rates reflect allowable deductions and tax credits and are applied to estimated future pre-tax net cash flows, less the tax basis of related assets. Discounted future net cash flows are calculated using 10 percent midperiod

discount factors. Discounting requires a year-by-year estimate of when future expenditures will be incurred and when reserves will be produced.

The information provided does not represent management's estimate of the company's expected future cash flows or value of proved oil and gas reserves. Estimates of proved-reserve quantities are imprecise and change over time as new information becomes available. Moreover, probable and possible reserves, which may become proved in the future, are excluded from the calculations. The valuation prescribed by the FASB 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 should not be relied upon as an indication of the company's future cash flows or value of its oil and gas reserves. In the following table, "Standardized Measure Net Cash Flows" refers to the standardized measure of discounted future net cash flows.

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

	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated Companies
<i>Millions of dollars</i>	U.S.	Other Americas	Africa	Asia	Australia	Europe	Total	TCO	Other	
At December 31, 2013										
Future cash inflows from production ¹	\$ 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)	(19,387)	(10,099)	(161,384)	(32,245)	(18,027)	(211,656)
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)	(27,904)	(4,727)	(150,658)	(33,603)	(9,418)	(193,679)
Undiscounted future net cash flows	57,417	24,492	24,383	32,802	65,109	2,762	206,965	78,408	12,056	297,429
10 percent midyear annual discount for timing of estimated cash flows	(23,055)	(15,217)	(8,165)	(10,901)	(35,110)	(888)	(93,336)	(41,444)	(6,482)	(141,262)
Standardized Measure										
Net Cash Flows	\$ 34,362	\$ 9,275	\$ 16,218	\$ 21,901	\$ 29,999	\$ 1,874	\$ 113,629	\$ 36,964	\$ 5,574	\$ 156,167
At December 31, 2012²										
Future cash inflows from production ¹	\$ 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)	(18,340)	(8,768)	(156,377)	(32,085)	(19,899)	(208,361)
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)	(27,224)	(5,589)	(154,518)	(37,658)	(13,363)	(205,539)
Undiscounted future net cash flows	54,534	20,645	34,313	38,098	63,522	3,350	214,462	87,868	10,524	312,854
10 percent midyear annual discount for timing of estimated cash flows	(23,055)	(14,331)	(12,429)	(13,033)	(40,450)	(860)	(104,158)	(47,534)	(5,644)	(157,336)
Standardized Measure										
Net Cash Flows	\$ 31,479	\$ 6,314	\$ 21,884	\$ 25,065	\$ 23,072	\$ 2,490	\$ 110,304	\$ 40,334	\$ 4,880	\$ 155,518
At December 31, 2011										
Future cash inflows from production ¹	\$ 143,633	\$ 63,579	\$124,077	\$124,972	\$ 113,773	\$ 19,704	\$ 589,738	\$ 171,588	\$ 42,212	\$ 803,538
Future production costs	(39,523)	(22,856)	(22,703)	(35,579)	(15,411)	(7,467)	(143,539)	(30,904)	(19,430)	(193,873)
Future development costs	(11,272)	(9,345)	(10,695)	(15,035)	(29,489)	(676)	(76,512)	(10,778)	(2,836)	(90,126)
Future income taxes	(34,050)	(9,121)	(53,103)	(33,884)	(20,661)	(7,229)	(158,048)	(36,698)	(10,833)	(205,579)
Undiscounted future net cash flows	58,788	22,257	37,576	40,474	48,212	4,332	211,639	93,208	9,113	313,960
10 percent midyear annual discount for timing of estimated cash flows	(25,013)	(15,082)	(13,801)	(14,627)	(35,051)	(1,117)	(104,691)	(51,547)	(4,883)	(161,121)
Standardized Measure										
Net Cash Flows	\$ 33,775	\$ 7,175	\$ 23,775	\$ 25,847	\$ 13,161	\$ 3,215	\$ 106,948	\$ 41,661	\$ 4,230	\$ 152,839

¹ Based on 12-month average price.

² 2012 conformed to 2013 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.”

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

<i>Millions of dollars</i>	Consolidated Companies*	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2011	\$ 73,024	\$ 35,619	\$ 108,643
Sales and transfers of oil and gas produced net of production costs	(52,338)	(8,679)	(61,017)
Development costs incurred	13,869	729	14,598
Purchases of reserves	1,212	—	1,212
Sales of reserves	(803)	—	(803)
Extensions, discoveries and improved recovery less related costs	12,288	—	12,288
Revisions of previous quantity estimates	16,025	923	16,948
Net changes in prices, development and production costs	61,428	15,979	77,407
Accretion of discount	11,943	5,048	16,991
Net change in income tax	(29,700)	(3,728)	(33,428)
Net change for 2011	33,924	10,272	44,196
Present Value at December 31, 2011	\$ 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	(1,630)	—	(1,630)
Extensions, discoveries and improved recovery less related costs	9,251	106	9,357
Revisions of previous quantity estimates	26,022	3,759	29,781
Net changes in prices, development and production costs	(19,178)	(2,266)	(21,444)
Accretion of discount	18,026	6,322	24,348
Net change in income tax	1,570	(1,832)	(262)
Net change for 2012	3,356	(677)	2,679
Present Value at December 31, 2012	\$ 110,304	\$ 45,214	\$ 155,518
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	25,573	1,306	26,879
Net changes in prices, development and production costs	(25,959)	(5,925)	(31,884)
Accretion of discount	18,463	6,406	24,869
Net change in income tax	2,539	2,818	5,357
Net change for 2013	3,325	(2,676)	649
Present Value at December 31, 2013	\$ 113,629	\$ 42,538	\$ 156,167

* 2012 conformed to 2013 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 size of 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, 57

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 is a member of the Board of Directors and the Executive Committee of the American Petroleum Institute. Joined Chevron in 1980.

George L. Kirkland, 63

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.

Linnet F. Deily, 68

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, 4)

Robert E. Denham, 68

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, 55

Director since 2012. She is President of Lehigh University in Bethlehem, Pennsylvania. Previously she served as Vice President for Research, Associate Provost and Robert T. Haslam Chair in Chemical Engineering at the Massachusetts Institute of Technology. (1)

Enrique Hernandez Jr., 58

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. (1, 2)



Jon M. Huntsman Jr., 54

Director since 2014. He is Chairman of the Board of Directors 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, 62

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. (2, 4)

Kevin W. Sharer, 66

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. (3, 4)

John G. Stumpf, 60

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, 65

Director since 2005. He is retired Chairman of the Board and Chief Executive Officer of Northrop Grumman Corporation, a global defense and technology company. Previously he was President and Chief Operating Officer of Northrop Grumman. He is a Director of Amgen Inc., Air Lease Corporation and Apple Inc. (1)

Carl Ware, 70

Director since 2001. He is a retired Executive Vice President of The Coca-Cola Company, a manufacturer of beverages. Previously he was a Senior Adviser to the Chief Executive Officer of The Coca-Cola Company and an Executive Vice President, Global Public Affairs and Administration, for The Coca-Cola Company. (3, 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, 61

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, 60

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, 49

Corporate Vice President and President, Chevron Gas and Midstream, since January 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.

Matthew J. Foehr, 56

Vice President and Comptroller since 2010. Responsible for corporatewide accounting, financial reporting and analysis, internal controls, and Finance Shared Services. Previously Vice President, Finance, Global Upstream and Gas, and Vice President, Finance, Global Downstream. Joined Chevron in 1982.

Joseph C. Geagea, 54

Senior Vice President, Technology, Projects and Services, since January 2014. Responsible for energy technology, delivery of major capital projects, procurement, information technology, 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, 56

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 1998.

James W. Johnson, 55

Senior Vice President, Upstream, since January 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, 61

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, 54

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, 59

Vice President since May 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 1980.

Joseph M. Naylor, 53

Vice President, Strategic Planning, since August 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.

R. Hewitt Pate, 51

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, 56

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, 53

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, 58

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

Rhonda I. Zygocki, 56

Executive Vice President, Policy and Planning, since 2011. Responsible for Strategic Planning; Health, Environment and Safety; Policy, Government and Public Affairs; Business and Real Estate Services; and Technology Ventures. Previously Corporate Vice President, Policy, Government and Public Affairs. 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, Patricia E. Yarrington and Rhonda I. Zygocki. 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. CDT, Wednesday, May 28, 2014, at: Permian Basin Petroleum Museum 1500 West Interstate 20 Midland, TX 79701-2041

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



2013 Annual Report



2013 Supplement to the Annual Report



2013 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/CorporateResponsibility, 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 website, Chevron.com/CorporateResponsibility.

Details of the company's *political contributions* for 2013 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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Chevron Corporation
6001 Bollinger Canyon Road
San Ramon, CA 94583-2324 USA
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