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

Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission File Number 001-00368

Chevron Corporation

(Exact name of registrant as specified in its charter)

Delaware	94-0890210	6001 Bollinger Canyon Road, San Ramon, California 94583-2324
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(Address of principal executive offices) (Zip Code)

Registrant’s telephone number, including area code (925) 842-1000
Securities registered pursuant to Section 12 (b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $.75 per share	New York Stock Exchange, Inc.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter — $247,905,549,754 (As of June 30, 2014)

Number of Shares of Common Stock outstanding as of February 9, 2015 — 1,880,180,422

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2015 Annual Meeting and 2015 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company’s 2015 Annual Meeting of Stockholders (in Part III)

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

This *Annual Report on Form 10-K* of Chevron Corporation contains forward-looking statements relating to Chevron's operations that are based on management's current expectations, estimates and projections about the petroleum, chemicals and other energy-related industries. Words such as "anticipates," "expects," "intends," "plans," "targets," "forecasts," "projects," "believes," "seeks," "schedules," "estimates," "may," "could," "budgets," "outlook" and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, many of which are beyond the company's control and are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this report. Unless legally required, Chevron undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: changing crude oil and natural gas prices; changing refining, marketing and chemicals margins; actions of competitors or regulators; timing of exploration expenses; timing of crude oil liftings; the competitiveness of alternate-energy sources or product substitutes; technological developments; the results of operations and financial condition of equity affiliates; the inability or failure of the company's joint-venture partners to fund their share of operations and development activities; the potential failure to achieve expected net production from existing and future crude oil and natural gas development projects; potential delays in the development, construction or start-up of planned projects; the potential disruption or interruption of the company's production or manufacturing facilities or delivery/transportation networks due to war, accidents, political events, civil unrest, severe weather, other natural or human factors, or crude oil production quotas that might be imposed by the Organization of Petroleum Exporting Countries; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant investment or product changes required by existing or future environmental statutes, regulations and litigation; the potential liability resulting from other pending or future litigation; the company's future acquisition or disposition of assets and gains and losses from asset dispositions or impairments; government-mandated sales, divestitures, recapitalizations, industry-specific taxes, changes in fiscal terms or restrictions on scope of company operations; foreign currency movements compared with the U.S. dollar; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; and the factors set forth under the heading "Risk Factors" on pages 22 through 24 in this report. 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.

PART I

Item 1. Business

General Development of Business

Summary Description of Chevron

Chevron Corporation,* a Delaware corporation, manages its investments in subsidiaries and affiliates and provides administrative, financial, management and technology support to U.S. and international subsidiaries that engage in fully integrated petroleum operations, chemicals operations, and power and energy services. Upstream operations consist primarily of exploring for, developing and producing crude oil and natural gas; processing, liquefaction, transportation and regasification associated with liquefied natural gas; transporting crude oil by major international oil export pipelines; transporting, storage and marketing of natural gas; and a gas-to-liquids plant. Downstream operations consist primarily of 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 fuel and lubricant additives.

A list of the company's major subsidiaries is presented on page E-4. As of December 31, 2014, Chevron had approximately 64,700 employees (including about 3,300 service station employees). Approximately 31,800 employees (including about 3,100 service station employees), or 49 percent, were employed in U.S. operations.

Overview of Petroleum Industry

Petroleum industry operations and profitability are influenced by many factors. Prices for crude oil, natural gas, petroleum products and petrochemicals are generally determined by supply and demand. Production levels from the members of the Organization of Petroleum Exporting Countries (OPEC) are a major factor in determining worldwide supply. Demand for crude oil and its products and for natural gas is largely driven by the conditions of local, national and global economies, although weather patterns and taxation relative to other energy sources also play a significant part. Laws and governmental policies, particularly in the areas of taxation, energy and the environment, affect where and how companies conduct their operations and formulate their products and, in some cases, limit their profits directly.

Strong competition exists in all sectors of the petroleum and petrochemical industries in supplying the energy, fuel and chemical needs of industry and individual consumers. Chevron competes with fully integrated, major global petroleum companies, as well as independent and national petroleum companies, for the acquisition of crude oil and natural gas leases and other properties and for the equipment and labor required to develop and operate those properties. In its downstream business, Chevron competes with fully integrated, major petroleum companies and other independent refining, marketing, transportation and chemicals entities and national petroleum companies in the sale or acquisition of various goods or services in many national and international markets.

Operating Environment

Refer to pages FS-2 through FS-9 of this Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the company's current business environment and outlook.

Chevron's Strategic Direction

Chevron's primary objective is to create shareholder value and achieve sustained financial returns from its operations that will enable it to outperform its competitors. In the upstream, the company's strategies are to grow profitably in core areas and build new legacy positions. In the downstream, the strategies are to deliver competitive returns and grow earnings across the value chain. The company also continues to apply commercial excellence in supply, trading and transportation to enable the success of the upstream and downstream strategies, and to utilize technology across all its businesses to differentiate performance.

Information about the company is available on the company's website at www.chevron.com. Information contained on the company's website is not part of this Annual Report on Form 10-K. The company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge on the company's website soon after such reports are filed with or furnished to the U.S. Securities and Exchange Commission (SEC). The reports are also available on the SEC's website at www.sec.gov.

* Incorporated in Delaware in 1926 as Standard Oil Company of California, the company adopted the name Chevron Corporation in 1984 and ChevronTexaco Corporation in 2001. In 2005, ChevronTexaco Corporation changed its name to Chevron Corporation. As used in this report, the term "Chevron" and such terms as "the company," "the corporation," "our," "we" and "us" may refer to Chevron Corporation, one or more of its consolidated subsidiaries, or all of them taken as a whole, but unless stated otherwise they do not include "affiliates" of Chevron — i.e., those companies accounted for by the equity method (generally owned 50 percent or less) or investments accounted for by the cost method. 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.

Description of Business and Properties

The upstream and downstream activities of the company and its equity affiliates are widely dispersed geographically, with operations and projects* in North America, South America, Europe, Africa, Asia and Australia. Tabulations of segment sales and other operating revenues, earnings and income taxes for the three years ending December 31, 2014, and assets as of the end of 2014 and 2013 — for the United States and the company's international geographic areas — are in Note 12 to the Consolidated Financial Statements beginning on page FS-37. Similar comparative data for the company's investments in and income from equity affiliates and property, plant and equipment are in Notes 13 and 14 on pages FS-40 through FS-41. Refer to page FS-13 of this Form 10-K in Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of the company's capital and exploratory expenditures.

Upstream

Reserves

Refer to Table V beginning on page FS-65 for a tabulation of the company's proved net liquids (including crude oil, condensate, natural gas liquids and synthetic oil) and natural gas reserves by geographic area, at the beginning of 2012 and each year-end from 2012 through 2014. Reserves governance, technologies used in establishing proved reserves additions, and major changes to proved reserves by geographic area for the three-year period ended December 31, 2014, are summarized in the discussion for Table V. Discussion is also provided regarding the nature of, status of, and planned future activities associated with the development of proved undeveloped reserves. The company recognizes reserves for projects with various development periods, sometimes exceeding five years. The external factors that impact the duration of a project include scope and complexity, remoteness or adverse operating conditions, infrastructure constraints, and contractual limitations.

At December 31, 2014, 20 percent of the company's net proved reserves were located in Kazakhstan and 19 percent were located in the United States.

The net proved reserve balances at the end of each of the three years 2012 through 2014 are shown in the following table:

	At December 31		
	2014	2013	2012
Liquids — Millions of barrels			
Consolidated Companies	**4,285**	4,303	4,353
Affiliated Companies	**1,964**	2,042	2,128
Total Liquids	**6,249**	6,345	6,481
Natural Gas — Billions of cubic feet			
Consolidated Companies	**25,707**	25,670	25,654
Affiliated Companies	**3,409**	3,476	3,541
Total Natural Gas	**29,116**	29,146	29,195
Oil-Equivalent — Millions of barrels*			
Consolidated Companies	**8,570**	8,582	8,629
Affiliated Companies	**2,532**	2,621	2,718
Total Oil-Equivalent	**11,102**	11,203	11,347

* Oil-equivalent conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of oil.

* As used in this report, the term "project" may describe new upstream development activity, individual phases in a multiphase development, maintenance activities, certain existing assets, new investments in downstream and chemicals capacity, investments in emerging and sustainable energy activities, and certain other activities. All of these terms are used for convenience only and are not intended as a precise description of the term "project" as it relates to any specific governmental law or regulation.

Net Production of Liquids and Natural Gas

The following table summarizes the net production of liquids and natural gas for 2014 and 2013 by the company and its affiliates. Worldwide oil-equivalent production of 2.571 million barrels per day in 2014 was down 1 percent from 2013. Production increases in the Permian Basin in Texas and New Mexico and the Marcellus Shale in western Pennsylvania, and project ramp-ups in Nigeria, Argentina and Brazil, were more than offset by normal field declines, production entitlement effects in several locations and the effect of asset sales. Refer to the "Results of Operations" section beginning on page FS-7 for a detailed discussion of the factors explaining the 2012 through 2014 changes in production for crude oil and natural gas liquids, and natural gas, and refer to Table V on pages FS-68 and FS-69 for information on annual production by geographical region.

			Components of Oil-Equivalent			
Thousands of barrels per day (MBPD)	**Oil-Equivalent (MBPD)[1]**		**Liquids (MBPD)**		**Natural Gas (MMCFPD)**	
Millions of cubic feet per day (MMCFPD)	**2014**	2013	**2014**	2013	**2014**	2013
United States	**664**	657	**456**	449	**1,250**	1,246
Other Americas						
Argentina	**25**	19	**21**	18	**23**	6
Brazil	**21**	6	**20**	5	**6**	2
Canada[2]	**69**	71	**67**	70	**10**	9
Colombia	**31**	36	**—**	—	**186**	216
Trinidad and Tobago	**19**	29	**—**	—	**112**	173
Total Other Americas	**165**	161	**108**	93	**337**	406
Africa						
Angola	**121**	127	**113**	118	**51**	52
Chad[3]	**8**	19	**8**	18	**2**	4
Democratic Republic of the Congo	**3**	3	**2**	2	**1**	1
Nigeria	**286**	268	**246**	238	**236**	182
Republic of the Congo	**16**	14	**14**	13	**11**	10
Total Africa	**434**	431	**383**	389	**301**	249
Asia						
Azerbaijan	**28**	28	**26**	26	**12**	10
Bangladesh	**109**	113	**2**	2	**643**	663
China	**16**	20	**16**	19	**—**	6
Indonesia	**185**	193	**149**	156	**214**	225
Kazakhstan	**53**	57	**31**	34	**126**	135
Myanmar	**16**	16	**—**	—	**99**	96
Partitioned Zone[4]	**81**	87	**78**	84	**18**	19
Philippines	**23**	23	**3**	3	**118**	119
Thailand	**238**	229	**63**	62	**1,046**	1,003
Total Asia	**749**	766	**368**	386	**2,276**	2,276
Australia/Oceania						
Australia	97	96	23	26	442	421
Total Australia/Oceania	**97**	96	**23**	26	**442**	421
Europe						
Denmark	**25**	28	**17**	19	**51**	55
Netherlands[3]	**7**	9	**2**	2	**34**	41
Norway[3]	**1**	2	**1**	2	**—**	1
United Kingdom	**47**	55	**32**	40	**88**	94
Total Europe	**80**	94	**52**	63	**173**	191
Total Consolidated Companies	**2,189**	2,205	**1,390**	1,406	**4,779**	4,789
Affiliates[2,5]	**382**	392	**319**	325	**388**	403
Total Including Affiliates[6]	**2,571**	2,597	**1,709**	1,731	**5,167**	5,192

[1] Oil-equivalent conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of oil.

[2] Includes synthetic oil: Canada, net	**43**	43	**43**	43	**—**	—
Venezuelan affiliate, net	**31**	25	**31**	25	**—**	—

[3] Producing fields in Chad, the Netherlands and Norway were sold in 2014.

[4] Located between Saudi Arabia and Kuwait.

[5] Volumes represent Chevron's share of production by affiliates, including Tengizchevroil in Kazakhstan; Petroboscan, Petroindependiente and Petropiar in Venezuela; and Angola LNG in Angola.

[6] Volumes include natural gas consumed in operations of 523 million and 530 million cubic feet per day in 2014 and 2013, respectively.[(7)] Total "as sold" natural gas volumes were 4,644 million and 4,662 million cubic feet per day for 2014 and 2013, respectively.[(7)]

[7] 2013 conformed to 2014 presentation.

Production Outlook

The company estimates its average worldwide oil-equivalent production in 2015 will be flat to 3 percent growth compared to 2014. This estimate is subject to many factors and uncertainties, as described beginning on page FS-4. Refer to the "Review of Ongoing Exploration and Production Activities in Key Areas," beginning on page 8, for a discussion of the company's major crude oil and natural gas development projects.

Average Sales Prices and Production Costs per Unit of Production

Refer to Table IV on page FS-64 for the company's average sales price per barrel of crude oil, condensate and natural gas liquids and per thousand cubic feet of natural gas produced, and the average production cost per oil-equivalent barrel for 2014, 2013 and 2012.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2014 for the company and its affiliates:

	At December 31, 2014			
	Productive Oil Wells		**Productive Gas Wells**	
	Gross	**Net**	**Gross**	**Net**
United States	50,338	32,957	13,393	7,098
Other Americas	937	642	61	33
Africa	1,980	676	17	7
Asia	14,144	12,213	3,431	2,043
Australia/Oceania	744	417	76	15
Europe	322	69	161	34
Total Consolidated Companies	68,465	46,974	17,139	9,230
Affiliates	1,405	486	7	2
Total Including Affiliates	69,870	47,460	17,146	9,232
Multiple completion wells included above	954	678	412	382

Acreage

At December 31, 2014, the company owned or had under lease or similar agreements undeveloped and developed crude oil and natural gas properties throughout the world. The geographical distribution of the company's acreage is shown in the following table:

	Undeveloped*		**Developed**		**Developed and Undeveloped**	
Thousands of acres	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	5,724	4,718	7,139	4,726	12,863	9,444
Other Americas	26,834	15,134	1,403	390	28,237	15,524
Africa	14,967	8,766	3,167	1,333	18,134	10,099
Asia	28,998	13,864	1,549	901	30,547	14,765
Australia/Oceania	19,338	13,640	912	235	20,250	13,875

Europe	4,718	3,464	407	53	5,125	3,517
Total Consolidated Companies	100,579	59,586	14,577	7,638	115,156	67,224
Affiliates	534	230	269	105	803	335
Total Including Affiliates	101,113	59,816	14,846	7,743	115,959	67,559

* The gross undeveloped acres that will expire in 2015, 2016 and 2017 if production is not established by certain required dates are 8,065, 3,913 and 2,110, respectively.

Delivery Commitments

The company sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Most contracts generally commit the company to sell quantities based on production from specified properties, but some natural gas sales contracts specify delivery of fixed and determinable quantities, as discussed below.

In the United States, the company is contractually committed to deliver 239 billion cubic feet of natural gas to third parties through 2017. The company believes it can satisfy these contracts through a combination of equity production from the company's proved developed U.S. reserves and third-party purchases. These commitments include a variety of pricing terms, including both indexed and fixed-price contracts.

Outside the United States, the company is contractually committed to deliver a total of 705 billion cubic feet of natural gas to third parties from 2015 through 2017 from operations in Australia, Colombia, Denmark and the Philippines. These sales contracts contain variable pricing formulas that are generally referenced to the prevailing market price for crude oil, natural gas or other petroleum products at the time of delivery. The company believes it can satisfy these contracts from quantities available from production of the company's proved developed reserves in these countries.

Development Activities

Refer to Table I on page FS-61 for details associated with the company's development expenditures and costs of proved property acquisitions for 2014, 2013 and 2012.

The following table summarizes the company's net interest in productive and dry development wells completed in each of the past three years, and the status of the company's development wells drilling at December 31, 2014. A "development well" is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

	Wells Drilling at 12/31/14		Net Wells Completed 2014		2013		2012	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**120**	**76**	**1,085**	**8**	1,101	4	941	6
Other Americas	**65**	**39**	**81**	**—**	127	—	50	—
Africa	**27**	**8**	**9**	**—**	20	1	23	—
Asia	**140**	**70**	**1,025**	**4**	535	5	566	6
Australia/Oceania	**9**	**7**	**9**	**—**	—	—	—	—
Europe	**3**	**—**	**2**	**—**	3	—	9	—
Total Consolidated Companies	**364**	**200**	**2,211**	**12**	1,786	10	1,589	12
Affiliates	**27**	**12**	**25**	**1**	25	—	26	—
Total Including Affiliates	**391**	**212**	**2,236**	**13**	1,811	10	1,615	12

Exploration Activities

Refer to Table I on page FS-61 for detail on the company's exploration expenditures and costs of unproved property acquisitions for 2014, 2013 and 2012.

The following table summarizes the company's net interests in productive and dry exploratory wells completed in each of the last three years, and the number of exploratory wells drilling at December 31, 2014. "Exploratory wells" are wells drilled to find and produce crude oil or natural gas in unproved areas and include delineation and appraisal wells, which are wells drilled to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir or to extend a known reservoir beyond the proved area.

	Wells Drilling at 12/31/14		Net Wells Completed 2014		2013		2012	
	Gross	Net	Prod.	Dry	Prod.	Dry	Prod.	Dry
United States	**13**	**7**	**20**	**12**	17	2	4	—
Other Americas	**8**	**3**	**3**	**—**	12	2	8	—
Africa	**2**	**1**	**1**	**2**	—	—	1	2
Asia	**—**	**—**	**7**	**2**	13	4	12	3
Australia/Oceania	**1**	**1**	**3**	**—**	3	—	3	—
Europe	**2**	**—**	**3**	**—**	2	2	1	2
Total Consolidated Companies	**26**	**12**	**37**	**16**	47	10	29	7
Affiliates	**—**	**—**	**—**	**—**	—	—	—	—
Total Including Affiliates	**26**	**12**	**37**	**16**	47	10	29	7

Review of Ongoing Exploration and Production Activities in Key Areas

Chevron has exploration and production activities in most of the world's major hydrocarbon basins. Chevron’s 2014 key upstream activities, some of which are also discussed in Management’s Discussion and Analysis of Financial Condition and Results of Operations, beginning on page FS-3, are presented below. The comments include references to “total production” and “net production,” which are defined under “Production” in Exhibit 99.1 on page E-10.

The discussion that follows references the status of proved reserves recognition for significant long-lead-time projects not on production as well as for projects recently placed on production. Reserves are not discussed for exploration activities or recent discoveries that have not advanced to a project stage, or for mature areas of production that do not have individual projects requiring significant levels of capital or exploratory investment. Amounts indicated for project costs represent total project costs, not the company’s share of costs for projects that are less than wholly owned.

United States

Upstream activities in the United States are primarily located in California, the Gulf of Mexico, Colorado, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, West Virginia and Wyoming. Average net oil-equivalent production in the United States during 2014 was 664,000 barrels per day.

In California, the company has significant production in the San Joaquin Valley. In 2014, net daily production averaged 163,000 barrels of crude oil, 66 million cubic feet of natural gas and 3,000 barrels of natural gas liquids (NGLs). Approximately 86 percent of the crude oil production is considered heavy oil (typically with API gravity lower than 22 degrees).

During 2014, net daily production in the Gulf of Mexico averaged 133,000 barrels of crude oil, 320 million cubic feet of natural gas and 15,000 barrels of NGLs. Chevron was engaged in various exploration and development activities in the deepwater Gulf of Mexico during 2014.

The Jack and St. Malo fields are being jointly developed with a host floating production unit (FPU) located between the two fields. Chevron has a 50 percent interest in the Jack Field and a 51 percent interest in the St. Malo Field. Both fields are company-operated. Chevron's interest in the production host facility is 40.6 percent. The facility has a design capacity of 170,000 barrels of crude oil and 42 million cubic feet of natural gas per day to accommodate production from the Jack/St. Malo development as well as third-party tiebacks. First production was achieved in December 2014, and production from three of 10 planned wells ramped-up during first quarter 2015. In addition, front-end engineering and design (FEED) activities continued in 2014 on the second phase of the development plan for the Jack and St. Malo fields, and construction is expected to commence on Stage 2 in 2016. Proved reserves have been recognized for this project. Production from the Jack/St. Malo development is expected to ramp up to a total daily rate of 94,000 barrels of crude oil and 21 million cubic feet of natural gas. The Jack and St. Malo fields have an estimated production life of 30 years from the time of start-up.

Construction and commissioning activities for the 60 percent-owned and operated Big Foot Project progressed during 2014, reaching 93 percent complete by year end. The project facilities have a design capacity of 75,000 barrels of crude oil and 25 million cubic feet of natural gas per day. First production is anticipated in late 2015. The field has an estimated production life of 35 years from the time of start-up. Proved reserves have been recognized for this project.

At the 58 percent-owned and operated Tahiti Field, work continued during 2014 on Tahiti 2 – a project that is designed to increase recovery from the main producing interval. The last injection well is expected to be completed in first quarter 2015. Additional infill drilling is scheduled for the Tahiti Field through 2016, with production from the first well expected in second-half 2015. The initial recognition of proved reserves occurred in 2014 for the infill drilling. The Tahiti Field has an estimated remaining production life of at least 20 years.

The company has a 42.9 percent nonoperated working interest in the Tubular Bells Field. First production was achieved in November 2014. Total production is expected to average 58,000 to 67,000 barrels of oil-equivalent per day in 2015. The field has an estimated production life of 25 years from the time of start-up.

The company has a 15.6 percent nonoperated working interest in the Mad Dog Field. The next development phase, the Mad Dog 2 Project, is planned to develop the southern portion of the field. The development plan was re-evaluated in 2013, and FEED was re-entered on a new development concept in third quarter 2014. At the end of 2014, proved reserves had not been recognized for this project.

Chevron holds a 25 percent nonoperated working interest in the Stampede Project, which includes the joint development of the Knotty Head and Pony fields. The planned facilities have a design capacity of 80,000 barrels of crude oil and 40 million cubic feet of natural gas per day. A final investment decision was reached in third quarter 2014. Drilling is planned to commence in fourth quarter 2015 with first oil expected in 2018. The fields have an estimated production life of 30 years from the time of start-up. The initial recognition of proved reserves occurred in 2014 for this project.

FEED activities commenced in early 2015 on a project to jointly develop the 55 percent-owned and operated Buckskin Field and the 87.5 percent-owned and operated Moccasin Field, which are located 12 miles apart. The development plan includes a subsea tieback to a third-party production facility with 30,000 barrels of crude oil and 15 million cubic feet of natural gas per day of firm capacity and rights to additional available capacity. A final investment decision is expected in 2016. At the end of 2014, proved reserves had not been recognized for this project.

In early 2015, the company announced a joint venture to explore and appraise 24 jointly held offshore leases in the northwest portion of Keathley Canyon. Chevron will be the operator. The joint venture includes the Tiber and Gila discoveries and the Gibson exploratory prospect, located between Gila and Tiber. The company acquired a 36 percent interest in the Gila leases and a 31 percent interest in the Tiber leases and also holds a 36 percent interest in the Gibson prospect. The scope of the joint venture includes further exploration and appraisal of the leases and evaluation of the potential for a centralized production facility. Separately, during 2014, the company exchanged its interest in the Coronado prospect for interests in other prospective deepwater exploration opportunities.

During 2014 and early 2015, the company participated in four appraisal wells and eight exploration wells in the deepwater Gulf of Mexico. An appraisal well and a sidetrack were completed at the Buckskin Field in 2014, and results are under evaluation. In October 2014, the company completed drilling an exploration well at the 42.5 percent-owned and operated Guadalupe prospect, which resulted in a significant crude oil discovery in the Lower Tertiary Wilcox Sands, adjacent to Keathley Canyon. Drilling at the 55 percent-owned and operated Anchor prospect was completed in December 2014, resulting in a significant crude oil discovery, also in the Lower Tertiary Wilcox Sands. In late 2014, drilling commenced on an appraisal well of the Tiber discovery as well as on a sidetrack of the Gila discovery well, and drilling is expected to continue until mid-2015. In January 2015, drilling commenced at the 40 percent-owned and operated Sweetwater and the 50 percent-owned and operated Sicily exploration wells, and both wells are expected to be completed in second quarter 2015.

In addition, Chevron added eleven leases to its deepwater portfolio as a result of awards from Gulf of Mexico lease sales held in 2014.

The company produces crude oil and natural gas in the midcontinent region of the United States, primarily in Colorado, New Mexico, Oklahoma, Texas and Wyoming. During 2014, the company’s net daily production in these areas averaged 110,000 barrels of crude oil, 595 million cubic feet of natural gas and 31,000 barrels of NGLs.

In the Permian Basin of West Texas and southeast New Mexico, the company continued to ramp-up development of shale and tight resources with drilling activities focused in the Midland and Delaware basins where the company holds approximately 500,000 and 1,000,000 net acres, respectively. The company drilled 550 wells in the Midland and Delaware basins in 2014.

The company holds leases in the Marcellus Shale and the Utica Shale, primarily located in southwestern Pennsylvania, eastern Ohio, and the West Virginia panhandle, and in the Antrim Shale and Collingwood/Utica Shale in Michigan. During 2014, the company's net daily production in these areas averaged 269 million cubic feet of natural gas. In 2014, development of the Marcellus Shale continued at a measured pace, focused on improving execution capability and reservoir understanding. Activities in the Utica Shale during 2014 focused on exploration drilling to acquire data necessary for potential future development.

Other Americas

“Other Americas” includes Argentina, Brazil, Canada, Colombia, Greenland, Suriname, Trinidad and Tobago, and Venezuela. Net oil-equivalent production from these countries averaged 228,000 barrels per day during 2014.

Canada: Upstream activities in Canada are concentrated in Alberta, British Columbia and the offshore Atlantic region. The company also has exploration interests in the Beaufort Sea region of the Northwest Territories. Average net oil-equivalent production during 2014 was 69,000 barrels per day, composed of 24,000 barrels of crude oil, 10 million cubic feet of natural gas and 43,000 barrels of synthetic oil from oil sands.

Chevron holds a 26.9 percent nonoperated working interest in the Hibernia Field, which comprises the Hibernia and Ben Nevis Avalon (BNA) reservoirs, and a 23.6 nonoperated working interest in the unitized Hibernia Southern Extension (HSE) areas offshore Atlantic Canada. In 2014, work continued on HSE development, and full production start-up is planned for 2015. Proved reserves have been recognized for this project. In addition, FEED activities progressed on the Hibernia SW BNA project. At the end of 2014, proved reserves had not been recognized for this project.

The company holds a 26.6 percent nonoperated working interest in the heavy oil Hebron Field, also offshore Atlantic Canada. The development plan includes a platform with a design capacity of 150,000 barrels of crude oil per day. Construction activities progressed in 2014. The project has an expected economic life of 30 years from the time of start-up, and first oil is expected in 2017. Proved reserves have been recognized for this project.

The company holds a 20 percent nonoperated working interest in the Athabasca Oil Sands Project (AOSP) in Alberta. Oil sands are mined from both the Muskeg River and the Jackpine mines, and bitumen is extracted from the oil sands and upgraded into synthetic oil. Construction work progressed during 2014 on the Quest Project, which is designed to capture and store more than one million tons of carbon dioxide produced annually by AOSP bitumen processing. Project start-up is expected in 2016.

The company holds approximately 228,000 net acres in the Duvernay Shale in Alberta and approximately 200,000 overlying acres in the Montney tight rock formation. Chevron has a 70 percent-owned and operated interest in most of the Duvernay acreage after completing a 30 percent farm-down in 2014. Production from the initial multiwell program in the Duvernay continued during 2014, and drilling activities began on an expanded 16-well appraisal program. A total of twelve wells had been tied into production facilities by early 2015.

Chevron holds a 50 percent-owned and operated interest in the proposed Kitimat LNG and Pacific Trail Pipeline projects and a 50 percent interest in 322,000 net acres in the Horn River and Liard shale gas basins in British Colombia. The Kitimat LNG Project is planned to include a two-train LNG facility and has a 10.0 million-metric-ton-per-year export license. The total production capacity for the project is expected to be 1.6 billion cubic feet of natural gas per day. Spending is being paced until LNG market conditions and reductions in project costs are sufficient to support the development of this project. At the end of 2014, proved reserves had not been recognized for this project.

The company holds a 40 percent nonoperated working interest in exploration rights for two blocks in the Flemish Pass Basin offshore Newfoundland.

Greenland: Chevron holds a 29.2 percent-owned and operated interest in Blocks 9 and 14 located in the Kanumas Area, offshore the northeast coast of Greenland. The acquisition of 2-D seismic data commenced in third quarter 2014 and is expected to continue over the next few years.

Argentina: In the Vaca Muerta Shale formation, Chevron holds a 50 percent nonoperated interest in two concessions covering 73,000 net acres. Chevron also holds an 85 percent-owned and operated interest in one concession covering 94,000 net acres with both conventional production and Vaca Muerta Shale potential. In addition, the company holds operated interests in three concessions covering 73,000 net acres in the Neuquen Basin, with interests ranging from 18.8 percent to 100 percent. Net oil-equivalent production in 2014 averaged 25,000 barrels per day, composed of 21,000 barrels of crude oil and 23 million cubic feet of natural gas.

Development activities continued at the Loma Campana concession in the Vaca Muerta Shale where 166 wells were drilled in 2014, and the 2015 drilling plan includes approximately 150 wells. In 2014, the company also continued production testing of four previously completed exploratory wells in the El Trapial concession, targeting oil and gas in the Vaca Muerta Shale. The El Trapial concession expires in 2032.

During 2014, the company signed agreements for exploration of shale oil and gas resources in the Narambuena area in the Chihuido de la Sierra Negra concession, also in the Vaca Muerta Shale. The exploration plan for Narambuena includes nine wells to be drilled in two phases.

Brazil: Chevron holds interests in three deepwater fields in the Campos Basin: Frade (51.7 percent-owned and operated), Papa-Terra and Maromba (37.5 percent and 30 percent nonoperated working interests, respectively). The concession that includes the Frade Field expires in 2025 and the concession that includes the Papa-Terra and Maromba fields expires in 2032. Net oil-equivalent production in 2014 averaged 21,000 barrels per day, composed of 20,000 barrels of crude oil and 6 million cubic feet of natural gas.

Following the resumption of production from four wells at the Frade Field during 2013, production resumed at the remaining six wells in second quarter 2014. At Papa-Terra, production is expected to ramp up through 2017 with additional development drilling until 2021.

Additionally, Chevron holds a 50 percent-owned and operated interest in Block CE-M715, located in the Ceara Basin offshore equatorial Brazil. Acquisition of 3-D seismic data is planned to commence in second quarter 2015.

Colombia: The company operates the offshore Chuchupa and the onshore Ballena and Riohacha natural gas fields and receives 43 percent of the production for the remaining life of each field and a variable production volume based on prior Chuchupa capital contributions. Daily net production averaged 186 million cubic feet of natural gas in 2014.

Suriname: Chevron holds a 50 percent nonoperated working interest in Blocks 42 and 45 offshore Suriname. In 2014, 2-D and 3-D seismic data for both blocks were processed. Farm-down opportunities are being pursued for the two blocks.

Trinidad and Tobago: The company has a 50 percent nonoperated working interest in three blocks in the East Coast Marine Area offshore Trinidad, which includes the Dolphin and Dolphin Deep producing natural gas fields and the Starfish development. Net production in 2014 averaged 112 million cubic feet of natural gas per day.

At the Starfish development, first gas was achieved in December 2014, and two additional wells are planned to be brought online in second quarter 2015. Natural gas from the project is planned to supply existing contractual commitments. Chevron also operates and holds a 50 percent interest in the Manatee Area of Block 6(d), where the Manatee discovery comprises a single cross-border field with Venezuela's Loran Field in Block 2. Work continued in 2014 on maturing commercial development concepts.

Venezuela: Chevron's production activities are performed by two affiliates in western Venezuela and one affiliate in the Orinoco Belt. Chevron has a 30 percent interest in the Petropiar affiliate that operates the Hamaca heavy oil production and upgrading project located in Venezuela's Orinoco Belt under an agreement expiring in 2033. Chevron also holds a 39.2 percent interest in the Petroboscan affiliate that operates the Boscan Field in western Venezuela and a 25.2 percent interest in the Petroindependiente affiliate that operates the LL-652 Field in Lake Maracaibo, both of which are under agreements expiring in 2026. The company's share of net oil-equivalent production during 2014 from these operations averaged 63,000 barrels per day, composed of 59,000 barrels of liquids and 27 million cubic feet of natural gas.

Chevron holds a 34 percent interest in the Petroindependencia affiliate that is working toward commercialization of Carabobo 3, a heavy oil project located within the Carabobo Area of the Orinoco Belt. The company also operates and holds a 60 percent interest in Block 2 and a 100 percent interest in Block 3 in the Plataforma Deltana area offshore eastern Venezuela. The Loran Field in Block 2 and the Manatee Field in Trinidad and Tobago form a single, cross-border field that lies along the maritime border of Venezuela and Trinidad and Tobago. Work continued in 2014 on maturing commercial development concepts.

Africa

In Africa, the company is engaged in upstream activities in Angola, Democratic Republic of the Congo, Liberia, Mauritania, Morocco, Nigeria, Republic of the Congo, Sierra Leone and South Africa. Net oil-equivalent production in this region averaged 439,000 barrels per day during 2014.

Angola: The company operates and holds a 39.2 percent interest in Block 0, a concession adjacent to the Cabinda coastline, and a 31 percent interest in a production-sharing contract (PSC) for deepwater Block 14. The concession for Block 0 extends through 2030 and the development and production rights for the various producing fields in Block 14 expire between 2023 and 2028. The company also has a 16.3 percent nonoperated working interest in the onshore Fina Sonangol Texaco concession area. Chevron's interest in Block 2 expired in July 2014. In addition, Chevron has a 36.4 percent interest in Angola LNG Limited. During 2014, net production from these operations averaged 114,000 barrels of liquids and 78 million cubic feet of natural gas per day.

Construction activities on Mafumeira Sul, the second development stage for the Mafumeira Field in Block 0, progressed in 2014. The facility has a design capacity of 150,000 barrels of liquids and 350 million cubic feet of natural gas per day. First production is planned for 2016, and ramp-up to full production is expected to continue through 2017. Proved reserves have been recognized for this project.

Work continued in 2014 on the Nemba Enhanced Secondary Recovery Stage 1 & 2 Project in Block 0. Installation of the platform was completed in early 2014, and start-up of the project is expected in early 2015. Total daily production is expected to be 9,000 barrels of crude oil. Proved reserves have been recognized for this project.

Also in Block 0, the company drilled one post-salt appraisal well in Area B and one pre-salt exploration well in Area A, which completed drilling in early 2015. As of early 2015, the results of both wells were under evaluation. One additional exploration well in Area A is planned to commence drilling in fourth quarter 2015.

In addition to the exploration and production activities, Angola LNG Limited operates an onshore natural gas liquefaction plant in Soyo, Angola. The plant has the capacity to process 1.1 billion cubic feet of natural gas per day, with expected average total daily sales of 670 million cubic feet of natural gas and up to 63,000 barrels of NGLs. This is the world's first LNG plant supplied with associated gas, where the natural gas is a by-product of crude oil production. Feedstock for the plant originates from multiple fields and operators. In April 2014, the plant experienced a failure in the flare blowdown piping system, resulting in an extended plant shutdown. Following a thorough review, a number of design issues have been identified that require modifications. Capacity and reliability enhancements are also planned to be completed during the shutdown. The plant will be restarted following completion of these modifications and repairs, and LNG production is expected to resume in late 2015. The remaining economic life of the project is anticipated to be in excess of 20 years.

The company also holds a 38.1 percent interest in the Congo River Canyon Crossing Pipeline project that is designed to transport up to 250 million cubic feet of natural gas per day from Block 0 and Block 14 to the Angola LNG plant. Construction on the project continued in 2014, with commissioning and start-up targeted for second-half 2015.

Angola-Republic of the Congo Joint Development Area: Chevron operates and holds a 31.3 percent interest in the Lianzi Unitization Zone, located in an area shared equally by Angola and Republic of the Congo. The Lianzi Project has a design capacity of 46,000 barrels of crude oil per day. Construction and drilling activities progressed during 2014, and first production is planned for fourth quarter 2015. Proved reserves have been recognized for this project.

Democratic Republic of the Congo: Chevron has a 17.7 percent nonoperated working interest in an offshore concession. Daily net production in 2014 averaged 2,000 barrels of crude oil.

Republic of the Congo: Chevron has a 31.5 percent nonoperated working interest in the offshore Haute Mer permit areas (Nkossa, Nsoko and Moho-Bilondo). The licenses for Nsoko, Nkossa, and Moho-Bilondo expire in 2018, 2027 and 2030, respectively. Net production averaged 14,000 barrels of liquids per day in 2014.

During 2014, work continued on the Moho Nord Project, located in the Moho-Bilondo development area. First production to the existing Moho-Bilondo FPU is expected in 2015, and total daily production of 140,000 barrels of crude oil is expected in 2017. Proved reserves have been recognized for this project.

In 2014, the company acquired a 20.4 percent nonoperated working interest in the Haute Mer B permit area, which covers more than 20,000 net acres offshore Republic of the Congo.

Chad/Cameroon: In June 2014, the company sold its 25 percent interest in seven crude oil fields in southern Chad and an approximate 21 percent interest in two affiliates that own the related crude oil export pipeline to the coast of Cameroon. Average daily net crude oil production from the Chad fields in 2014 was 8,000 barrels.

Liberia: Chevron operates and holds a 45 percent interest in three deepwater blocks off the coast of Liberia. In 2014, Chevron requested, and the government of Liberia granted, a one-year extension of the LB-11 and LB-12 blocks.

Sierra Leone: The company is the operator of and holds a 55 percent interest in a concession off the coast of Sierra Leone that contains two deepwater blocks. In 2014, 2-D seismic processing was completed to identify drilling prospects.

Mauritania: In early 2015, the company reached an agreement to acquire a 30 percent nonoperated working interest in the C8, C12 and C13 contract areas offshore Mauritania. The blocks cover 2 million net acres and have a water depth between 5,000 and 10,000 feet. The acquisition is pending government approval.

Morocco: The company operates and holds a 75 percent interest in three deepwater areas offshore Morocco. The acquisition of 2-D seismic data was completed in 2014, and a 3-D seismic survey is planned for 2015. Chevron is pursuing a farm-down of its interest.

Nigeria: Chevron holds a 40 percent interest in nine operated concessions, predominantly in the onshore and near-offshore regions of the Niger Delta. The company also holds acreage positions in three operated and six nonoperated deepwater blocks, with working interests ranging from 20 percent to 100 percent. The company is pursuing selected opportunities for divestment and farm-down in Nigeria. In 2014, the company’s net oil-equivalent production in Nigeria averaged 286,000 barrels per day, composed of 240,000 barrels of crude oil, 236 million cubic feet of natural gas and 6,000 barrels of liquefied petroleum gas.

Chevron operates and holds a 67.3 percent interest in the Agbami Field, located in deepwater Oil Mining Lease (OML) 127 and OML 128. During 2014, drilling continued on a second phase development program, Agbami 2, that is expected to offset field declines and maintain a total daily liquids production rate of 250,000 barrels. The third development phase, Agbami 3, is also expected to offset field declines. The project entered FEED in early 2014, and drilling for this phase commenced in early 2015. The drilling programs for Agbami 2 and Agbami 3 are scheduled to end in 2015 and 2017, respectively. The first Phase 3 development well is scheduled to commence production in 2016. The leases that contain the Agbami Field expire in 2023 and 2024. Proved reserves have been recognized for the Agbami 3 Project.

Also in the deepwater area, the Aparo Field in OML 132 and OML 140 and the third-party-owned Bonga SW Field in OML 118 share a common geologic structure and are planned to be jointly developed. Chevron holds a 19.6 percent nonoperated working interest in the unitized area. The planned facilities have a design capacity of 225,000 barrels of crude oil per day. A final investment decision is expected in 2015 or 2016. At the end of 2014, no proved reserves were recognized for this project.

In the Niger Delta region, ramp-up activity continued at the Escravos Gas Plant (EGP). During 2014, construction continued on Phase 3B of the EGP project, which is designed to gather 120 million cubic feet of natural gas per day from eight near-shore fields and to compress and transport the natural gas to onshore facilities. The Phase 3B project is expected to be completed in 2016. Proved reserves associated with this project have been recognized.

Construction activities progressed during 2014 on the 40 percent-owned and operated Sonam Field Development Project, which is designed to process natural gas through EGP, deliver 215 million cubic feet of natural gas per day to the domestic market and produce a total of 30,000 barrels of liquids per day. First production is expected in 2017. Proved reserves have been recognized for the project.

Chevron is the operator of a 33,000-barrel-per-day gas-to-liquids facility at Escravos. The facility is designed to process 325 million cubic feet per day of natural gas. The facility achieved initial production of product in mid-2014.

In deepwater exploration, Chevron operates and holds a 95 percent interest in the deepwater Nsiko discovery in OML 140, where drilling commenced on an exploration well at the Nsiko North prospect in fourth quarter 2014. Additional exploration activities are planned for 2015. In addition, Chevron holds a 30 percent nonoperated working interest in OML 138. In 2014, two exploration wells were drilled in the Usan area that resulted in crude oil discoveries. In 2015, the company plans to evaluate development options.

Shallow-water exploration activities to identify and evaluate potential deep hydrocarbon targets are ongoing. Reprocessing of 3-D seismic data over OML 49 and regional mapping activities over the western Niger Delta continued in 2014. Acquisition of 3-D seismic data over the Meren and Okan fields is planned for 2015.

With a 36.7 percent interest, Chevron is the largest shareholder in the West African Gas Pipeline Company Limited affiliate, which owns and operates the 421-mile West African Gas Pipeline. The pipeline supplies Nigerian natural gas to customers in Benin, Ghana and Togo for industrial applications and power generation and has the capacity to transport 170 million cubic feet per day.

South Africa: In 2014, the company continued evaluating shale gas exploration opportunities in the Karoo Basin in South Africa under an agreement that allows Chevron and its partner to work together to obtain exploration permits in the 151 million-acre basin.

Asia

In Asia, the company is engaged in upstream activities in Azerbaijan, Bangladesh, China, Indonesia, Kazakhstan, the Kurdistan Region of Iraq, Myanmar, the Partitioned Zone located between Saudi Arabia and Kuwait, the Philippines, Russia, Thailand, and Vietnam. During 2014, net oil-equivalent production averaged 1,063,000 barrels per day.

Azerbaijan: Chevron holds an 11.3 percent nonoperated working interest in the Azerbaijan International Operating Company (AIOC) and the crude oil production from the Azeri-Chirag-Gunashli (ACG) fields. The company's daily net production in 2014 averaged 28,000 barrels of oil-equivalent, composed of 26,000 barrels of crude oil and 12 million cubic feet of natural gas. AIOC operations are conducted under a PSC that expires in 2024.

The Chirag Oil Project is further developing the Chirag and Gunashli fields. The project has an incremental design capacity of 183,000 barrels of crude oil and 285 million cubic feet of natural gas per day. Production commenced in January 2014 and reached 84,000 barrels of crude oil and 87 million cubic feet of natural gas per day by year-end 2014.

Chevron also has an 8.9 percent interest in the Baku-Tbilisi-Ceyhan (BTC) Pipeline affiliate, which transports the majority of ACG production from Baku, Azerbaijan, through Georgia to Mediterranean deepwater port facilities at Ceyhan, Turkey. The BTC pipeline has a capacity of 1 million barrels per day. Another production export route for crude oil is the Western Route Export Pipeline, which is operated by AIOC, with capacity to transport 100,000 barrels per day from Baku, Azerbaijan, to a marine terminal at Supsa, Georgia.

Kazakhstan: Chevron has a 50 percent interest in the Tengizchevroil (TCO) affiliate and an 18 percent nonoperated working interest in the Karachaganak Field. Net oil-equivalent production in 2014 averaged 367,000 barrels per day, composed of 290,000 barrels of liquids and 460 million cubic feet of natural gas.

TCO is developing the Tengiz and Korolev crude oil fields in western Kazakhstan under a concession agreement that expires in 2033. Net daily production in 2014 from these fields averaged 239,000 barrels of crude oil, 334 million cubic feet of natural gas and 20,000 barrels of NGLs. The majority of TCO's crude oil production was exported through the Caspian Pipeline Consortium (CPC) pipeline that runs from Tengiz in Kazakhstan to tanker-loading facilities at Novorossiysk on the Russian coast of the Black Sea. The balance of production was exported by rail to Black Sea ports and via the BTC pipeline to the Mediterranean.

In 2014, work progressed on three projects. The Wellhead Pressure Management Project (WPMP) is designed to maintain production capacity and extend the production plateau from existing assets. The Capacity and Reliability (CAR) Project is designed to reduce facility bottlenecks and increase plant efficiency and reliability. The Future Growth Project (FGP) is designed to increase total daily production by 250,000 to 300,000 barrels of oil-equivalent and to increase ultimate recovery from the reservoir. The FGP is planned to expand the utilization of sour gas injection technology proven in existing operations. The final investment decision for the CAR Project was reached in February 2014. The final investment decisions for the FGP and the WPMP are anticipated in 2015. Proved reserves have been recognized for the WPMP and the CAR Project.

The Karachaganak Field is located in northwest Kazakhstan, and operations are conducted under a PSC that expires in 2038. During 2014, net daily production averaged 31,000 barrels of liquids and 126 million cubic feet of natural gas. Access to the CPC and Atyrau-Samara (Russia) pipelines enabled most of the Karachaganak liquids to be exported and sold at world-market prices during 2014. The remaining liquids were sold into local and Russian markets.

Kazakhstan/Russia: Chevron has a 15 percent interest in the CPC affiliate. During 2014, CPC transported an average of 865,000 barrels of crude oil per day, composed of 763,000 barrels per day from Kazakhstan and 102,000 barrels per day from Russia. In 2014, work continued on the 670,000-barrel-per-day expansion of the pipeline capacity. The project is being implemented in phases, with capacity increasing progressively until reaching a design capacity of 1.4 million barrels per day in 2016. By the end of 2014, capacity from Kazakhstan had been increased by a maximum of 230,000 barrels per day, and in December, nearly 90 percent of TCO's total production was exported via CPC. Additional capacity is expected to progressively come on line in 2015 and 2016. The expansion is expected to provide additional transportation capacity that accommodates a portion of the future growth in TCO production.

Bangladesh: Chevron operates and holds a 100 percent interest in Block 12 (Bibiyana Field) and Blocks 13 and 14 (Jalalabad and Moulavi Bazar fields). The rights to produce from Jalalabad expire in 2024, from Moulavi Bazar in 2028 and from Bibiyana in 2034. Net oil-equivalent production from these operations in 2014 averaged 109,000 barrels per day, composed of 643 million cubic feet of natural gas and 2,000 barrels of condensate.

First production was achieved in late 2014 at the Bibiyana Expansion Project, which has an incremental design capacity of 300 million cubic feet of natural gas and 4,000 barrels of condensate per day. The expected economic life of the project is the duration of the PSC. FEED activities continued on the Bibiyana Compression Project during 2014. The project is expected to provide incremental production to offset field declines. A final investment decision is pending commercial negotiations. At the end of 2014, proved reserves had not been recognized for this project.

Cambodia: In October 2014, Chevron completed the sale of its 30 percent interest in Block A, located in the Gulf of Thailand.

China: Chevron has operated and nonoperated working interests in several areas in China. The company's net production in 2014 averaged 16,000 barrels of crude oil per day.

The company operates and holds a 49 percent interest in the Chuandongbei Project, located onshore in the Sichuan Basin. The full development includes two sour gas processing plants connected by a natural gas gathering system to five fields. In 2014, the company continued construction on the first natural gas processing plant and development of the Luojiazhai and Gunziping natural gas fields. The first plant's initial three trains have a design outlet capacity of 258 million cubic feet per day. The first train reached mechanical completion in late 2014, and commissioning activities were initiated. Start-up is expected in 2015. The total design outlet capacity for the project is 558 million cubic feet per day. Proved reserves have been recognized for the natural gas fields supplying the first sour gas processing plant. The project's estimated economic life exceeds 20 years from start-up. The PSC for Chuandongbei expires in 2038.

Chevron has a 100 percent-owned and operated interest in shallow-water Blocks 15/10 and 15/28 in the South China Sea. In 2014, the company completed processing of two 3-D seismic surveys and plans to drill one exploration well in Block 15/10 in 2015. In May 2014, the company relinquished its interest in deepwater exploration Block 42/05.

The company also has nonoperated working interests of 24.5 percent in the QHD 32-6 Field and 16.2 percent in Block 11/19 in the Bohai Bay, and 32.7 percent in Block16/19 in the Pearl River Mouth Basin. The PSCs for these producing assets expire between 2022 and 2028.

Indonesia: Chevron holds working interests through various PSCs in Indonesia. In Sumatra, the company holds a 100 percent-owned and operated interest in the Rokan PSC. Chevron also operates four PSCs in the Kutei Basin, located offshore eastern Kalimantan. These interests range from 62 percent to 92.5 percent. In addition, Chevron holds a 25 percent nonoperated working interest in Block B in the South Natuna Sea. The company’s net oil-equivalent production in 2014 from its interests in Indonesia averaged 185,000 barrels per day, composed of 149,000 barrels of liquids and 214 million cubic feet of natural gas.

The largest producing field is Duri, located in the Rokan PSC. Duri has been under steamflood since 1985 and is one of the world’s largest steamflood developments. The company continues to implement projects designed to sustain production from existing reservoirs. Production ramp-up continued and first steam injection was achieved in 2014 at the steamflood expansion project in Area 13 of the Duri Field. The Rokan PSC expires in 2021.

There are two deepwater natural gas development projects in the Kutei Basin progressing under a single plan of development. Collectively, these projects are referred to as the Indonesia Deepwater Development. One of these projects, Bangka, has a design capacity of 115 million cubic feet of natural gas and 4,000 barrels of condensate per day. The company’s interest is 62 percent. A final investment decision was reached in 2014, following government approvals. Project execution began with the drilling of two development wells in second-half 2014. First gas is planned for 2016. The initial recognition of proved reserves occurred in 2014 for this project.

The other project, Gendalo-Gehem, has a planned design capacity of 1.1 billion cubic feet of natural gas and 47,000 barrels of condensate per day. The company's interest is approximately 63 percent. The company continues to work toward a final investment decision, subject to the timing of government approvals, rebidding of the engineering and construction contracts, extension of the associated PSCs, and securing new LNG sales contracts. At the end of 2014, proved reserves had not been recognized for this project.

Chevron relinquished its 51 percent-owned and operated interest in the West Papua I and West Papua III PSCs. Government approval for the relinquishment is anticipated in 2015.

In West Java, the company operates the Darajat geothermal field and holds a 95 percent interest in two power plants. The field supplies steam to a power plant with a total operating capacity of 270 megawatts. Chevron also operates and holds a 100 percent interest in the Salak geothermal field in West Java, which supplies steam to a six-unit power plant, three of which are company owned, with a total operating capacity of 377 megawatts. The company relinquished its 95 percent interest in the Suoh-Sekincau prospect area of South Sumatra. In 2014, Chevron secured the preliminary survey assignment for the adjacent South Sekincau prospect and is in the early phases of geological and geophysical assessment.

Myanmar: Chevron has a 28.3 percent nonoperated working interest in a PSC for the production of natural gas from the Yadana and Sein fields, within Blocks M5 and M6, in the Andaman Sea. The PSC expires in 2028. The company also has a 28.3 percent nonoperated interest in a pipeline company that transports most of the natural gas to the Myanmar-Thailand border for delivery to power plants in Thailand. The company’s average net natural gas production in 2014 was 99 million cubic feet per day.

In March 2014, Chevron was granted a 99 percent interest in and operatorship of Block A5. The exploration block covers 2.6 million net acres. As of early 2015, PSC terms were being finalized.

Philippines: The company holds a 45 percent nonoperated working interest in the Malampaya natural gas field, offshore Palawan. Net oil-equivalent production in 2014 averaged 23,000 barrels per day, composed of 118 million cubic feet of natural gas and 3,000 barrels of condensate. The Malampaya Phase 2 Project is designed to maintain capacity at the offshore platform. First production from the infill wells commenced in 2013, with first production from the compression facilities expected in second-half 2015. Proved reserves have been recognized for this project.

Chevron holds a 40 percent interest in an affiliate that develops and produces steam resources in southern Luzon, which supplies steam to third-party power generation facilities with a combined operating capacity of 692 megawatts. The renewable energy service contract expires in 2038. Chevron also has an interest in the Kalinga geothermal prospect area in northern Luzon. The company continues to assess the prospect area.

Thailand: Chevron holds operated interests in the Pattani Basin, located in the Gulf of Thailand, with ownership ranging from 35 percent to 80 percent. Concessions for producing areas within this basin expire between 2020 and 2035. Chevron also has a 16 percent nonoperated working interest in the Arthit Field located in the Malay Basin. Concessions for the producing areas within this basin expire between 2036 and 2040. The company's net oil-equivalent production in 2014 averaged 238,000 barrels per day, composed of 63,000 barrels of crude oil and condensate and 1 billion cubic feet of natural gas.

In the Pattani Basin, FEED activities continued for the 35 percent-owned and operated Ubon Project in Block 12/27. The development concept includes facilities with a planned design capacity of 35,000 barrels of liquids and 115 million cubic feet of natural gas per day. At the end of 2014, proved reserves had not been recognized for this project.

During 2014, the company drilled six exploration wells in the Pattani Basin, and four were successful. The company also holds exploration interests in the Thailand-Cambodia overlapping claim area that are inactive, pending resolution of border issues between Thailand and Cambodia.

Vietnam: Chevron is the operator of two PSCs in the Malay Basin off the southwest coast of Vietnam. The company has a 42.4 percent interest in a PSC that includes Blocks B and 48/95 and a 43.4 percent interest in a PSC for Block 52/97.

The Block B Gas Development Project facilities have a planned design capacity of 640 million cubic feet of natural gas and 21,000 barrels of liquids per day. A final investment decision for the development is pending resolution of commercial terms. Concurrent with the commercial negotiations, the company is also evaluating these assets for possible divestment. At the end of 2014, proved reserves had not been recognized for the development project.

Kurdistan Region of Iraq: The company operates and holds 80 percent contractor interests in three PSCs covering the Rovi, Sarta and Qara Dagh blocks. Initial drilling operations in the Rovi and Sarta blocks continued to progress in 2014, and the results are under evaluation. The company also commenced 3-D and 2-D seismic acquisition programs in the Sarta and Qara Dagh blocks, respectively. In August 2014, all activities were temporarily suspended as a result of ongoing regional instability. In early 2015, mobilization of personnel back to the region commenced in preparation to restart operations in first quarter. Farm-down opportunities are being pursued for the three blocks.

Partitioned Zone: Chevron holds a concession to operate the Kingdom of Saudi Arabia's 50 percent interest in the hydrocarbon resources in the onshore area of the Partitioned Zone between Saudi Arabia and Kuwait. The concession expires in 2039. During 2014, the company's average net oil-equivalent production was 81,000 barrels per day, composed of 78,000 barrels of crude oil and 18 million cubic feet of natural gas. Current difficulties in securing work and equipment permits may impact the company’s ability to continue production at current levels.

During 2014, the company continued a steam injection pilot project in the First Eocene carbonate reservoir. Proved reserves have been recognized for this project.

FEED activities continued on a project to expand the steam injection pilot to the Second Eocene reservoir, and a final investment decision is planned for 2016. Development planning also continued on a full-field steamflood application in the Wafra Field. The Wafra Steamflood Stage 1 Project has a planned design capacity of 80,000 barrels of crude oil per day and is expected to enter FEED in third quarter 2015. At the end of 2014, proved reserves had not been recognized for these steamflood developments.

The Central Gas Utilization Project is intended to increase natural gas utilization and eliminate routine flaring at the Wafra Field. As of early, 2015, the development plan is being re-evaluated. At year-end 2014, proved reserves had not been recognized for this project.

In June 2014, the company began a 3-D seismic survey covering the entire onshore Partitioned Zone.

Australia/Oceania

In Australia/Oceania, the company is engaged in upstream activities in Australia and New Zealand. During 2014, net oil-equivalent production averaged 97,000 barrels per day, all from Australia.

Australia: Upstream activities in Australia are concentrated offshore Western Australia, where the company is the operator of two major LNG projects, Gorgon and Wheatstone, and has a nonoperated working interest in the North West Shelf (NWS) Venture and exploration acreage in the Browse Basin and the Carnarvon Basin. The company also holds exploration acreage in the Nappamerri Trough in central Australia and the Bight Basin offshore South Australia. During 2014, the company's production averaged 23,000 barrels of crude oil and 442 million cubic feet of natural gas per day. Most of this production was from the NWS Venture.

Chevron holds a 47.3 percent interest and is the operator of the Gorgon Project, which includes the development of the Gorgon and nearby Jansz-Io fields. The project includes a three-train, 15.6 million-metric-ton-per-year LNG facility, a carbon dioxide injection facility and a domestic natural gas plant, which are located on Barrow Island, off Western Australia. The total production capacity for the project is expected to be approximately 2.6 billion cubic feet of natural gas and 20,000 barrels of condensate per day. Work continued during 2014 with 88 percent of the overall project complete at year-end. LNG Train 1 start-up is planned for third quarter 2015, with first cargo anticipated in fourth quarter 2015. Start-up of Trains 2 and 3 is expected in 2016. Total estimated project costs for the first phase of development are $54 billion. Proved reserves have been recognized for this project. The project's estimated economic life exceeds 40 years from the time of start-up.

In January 2015, the company announced an additional binding sales agreement for delivery of LNG from the Gorgon Project for a five-year period starting in 2017. During the time of this agreement, more than 75 percent of Chevron's equity LNG offtake from the project is committed under binding sales agreements with customers in Asia. Chevron also has binding, long-term agreements for delivery of about 65 million cubic feet per day of natural gas to Western Australian natural gas consumers, and the company continues to market additional pipeline natural gas quantities from the project.

The evaluation of options to increase the production capacity of Gorgon is planned to continue in 2015.

Chevron is the operator of the Wheatstone Project, which includes a two-train, 8.9 million-metric-ton-per-year LNG facility and a domestic gas plant, both located at Ashburton North, on the coast of Western Australia. The company plans to supply natural gas to the facilities from the Wheatstone and Iago fields. Chevron holds an 80.2 percent interest in the offshore licenses and a 64.1 percent interest in the LNG facilities. The total production capacity for the Wheatstone and Iago fields and nearby third party fields is expected to be approximately 1.6 billion cubic feet of natural gas and 30,000 barrels of condensate per day. The project was 53 percent complete at year-end. Start-up of the first train is expected in late 2016, with the second train start-up planned for 2017. Total estimated costs for the foundation phase are $29 billion. Proved reserves have been recognized for this project. The project's estimated economic life exceeds 30 years from the time of start-up.

As of year-end 2014, Chevron had binding, long-term sales agreements with four customers in Japan for 85 percent of the company's equity LNG offtake from this project. In addition, the company continues to market its equity share of pipeline natural gas to Western Australia customers.

During 2014, the company made five natural gas discoveries in the Carnarvon Basin. These discoveries contribute to the resources available to extend and expand Chevron's LNG projects in the region.

Chevron has a 16.7 percent nonoperated working interest in the North West Shelf (NWS) Venture in Western Australia. Approximately 80 percent of the natural gas sales were in the form of LNG to major utilities in Asia, primarily under long-term contracts. The remaining natural gas was sold to the Western Australia domestic market. The concession for the NWS Venture expires in 2034.

The company holds nonoperated working interests ranging from 24.8 percent to 50 percent in three blocks in the Browse Basin. Drilling in third quarter 2014 resulted in a natural gas discovery at the Lasseter prospect in Block WA-274-P.

In the Nappamerri Trough, the company holds a 30 percent nonoperated working interest in the Permian section of PRL 33-49 in South Australia and an 18 percent nonoperated working interest in ATP 855 in Queensland. During 2014, exploration drilling and flow testing continued in order to evaluate the commerciality of the resource base. Pending favorable results, Chevron could earn a 60 percent nonoperated working interest in PRL 33-49 and a 36 percent nonoperated working interest in ATP 855.

The company operates and holds a 100 percent working interest in offshore Blocks EPP44 and EPP45 in the Bight Basin off the South Australian coast. In 2014, the company completed the initial survey to acquire 3-D seismic data, and an additional survey and data processing are planned to continue through 2016.

New Zealand: In late 2014, Chevron was granted three exploration permits in the offshore Pegasus and East Coast basins. The deepwater permits cover 3.1 million net acres and are located approximately 100 miles east of Wellington. Chevron will be the operator with a 50 percent interest. The exploration permits are granted for a term of 15 years, commencing April 2015. Acquisition of 2-D and 3-D seismic data is scheduled to commence in 2016.

Europe

In Europe, the company is engaged in upstream activities in Denmark, Norway, Poland, Romania, and the United Kingdom. Net oil-equivalent production in the region averaged 80,000 barrels per day during 2014.

Denmark: Chevron holds a 12 percent nonoperated working interest in the Danish Underground Consortium (DUC), which produces crude oil and natural gas from 13 North Sea fields. Net oil-equivalent production in 2014 from the DUC averaged 25,000 barrels per day, composed of 17,000 barrels of crude oil and 51 million cubic feet of natural gas. The concession expires in 2042.

Lithuania: Chevron divested its 50 percent interest in an exploration and production company in mid-2014.

Netherlands: In November 2014, Chevron divested its upstream interests in the Dutch sector of the North Sea. Net oil-equivalent production in 2014 was 7,000 barrels per day, composed of 2,000 barrels of crude oil and 34 million cubic feet of natural gas.

Norway: In August 2014, the company completed the sale of its interest in the Draugen Field. Net production averaged 1,000 barrels of oil-equivalent per day during 2014. Chevron is the operator and has a 40 percent interest in exploration licenses PL 527 and PL 598. Both licenses are in the deepwater portion of the Norwegian Sea.

Poland: In first-half 2014, Chevron completed a 3-D seismic survey on the Grabowiec concession. The company also entered into a joint exploration agreement covering Chevron's Grabowiec and Zwierzyniec licenses and two adjacent licenses in early 2014. In fourth quarter 2014, Chevron relinquished two shale concessions (Frampol and Krasnik) in southeastern Poland. In early 2015, Chevron announced the discontinuation of exploration activities in Poland.

Romania: In 2014, drilling of the first exploration well in the Barlad Shale concession in northeast Romania was completed, as was a 2-D seismic survey across two of the three concessions in southeast Romania. Chevron intends to pursue relinquishment of its interest in these concessions in 2015.

Ukraine: In 2013, Chevron signed a PSC with the government of Ukraine for a 50 percent interest and operatorship of the Oleska Shale block in western Ukraine. In fourth quarter 2014, Chevron terminated the agreement.

United Kingdom: The company’s average net oil-equivalent production in 2014 from nine offshore fields was 47,000 barrels per day, composed of 32,000 barrels of liquids and 88 million cubic feet of natural gas. Most of the company's production was from three fields: the 85 percent-owned and operated Captain Field, the 23.4 percent-owned and operated Alba Field, and the 32.4 percent-owned and jointly operated Britannia Field.

The 73.7 percent-owned and operated Alder Project is being developed as a tie-back to the existing Britannia platform, and has a design capacity of 14,000 barrels of condensate and 110 million cubic feet of natural gas per day. Fabrication of topside and subsea equipment progressed in 2014, and first production is expected in 2016. Proved reserves have been recognized for this project.

The Captain Enhanced Oil Recovery Project is the next development phase of the Captain Field and is designed to increase field recovery. The project entered FEED in fourth quarter 2014, and a final investment decision is scheduled for 2016. At the end of 2014, proved reserves had not been recognized for this project.

During 2014, procurement and fabrication activities continued for the Clair Ridge Project, located west of the Shetland Islands, in which the company has a 19.4 percent nonoperated working interest. The project is the second development phase of the Clair Field. The design capacity of the project is 120,000 barrels of crude oil and 100 million cubic feet of natural gas per day. Production is scheduled to begin in 2017. The Clair Field has an estimated production life until 2050. Proved reserves have been recognized for the Clair Ridge Project.

At the 40 percent-owned and operated Rosebank Project northwest of the Shetland Islands, the company continued to assess alternatives for the optimum development of the Rosebank Field and made significant progress in optimizing the Rosebank development plan. The design capacity of the project is 100,000 barrels of crude oil and 80 million cubic feet of natural gas per day. At the end of 2014, proved reserves had not been recognized for this project.

West of the Shetland Islands, exploration activities included acquisition and interpretation of 3-D seismic data. In the central North Sea, an exploration well previously drilled to delineate the southern extension of the Jade Field was successfully tied back and first production was achieved.

Sales of Natural Gas and Natural Gas Liquids

The company sells natural gas and natural gas liquids from its producing operations under a variety of contractual arrangements. In addition, the company also makes third-party purchases and sales of natural gas and natural gas liquids in connection with its supply and trading activities.

During 2014, U.S. and international sales of natural gas were 4.0 billion and 4.3 billion cubic feet per day, respectively, which includes the company’s share of equity affiliates’ sales. Outside the United States, substantially all of the natural gas sales from the company’s producing interests are from operations in Australia, Bangladesh, Canada, Europe, Kazakhstan, Indonesia, Latin America, Myanmar, Nigeria, the Philippines and Thailand.

U.S. and international sales of natural gas liquids were 141,000 and 86,000 barrels per day, respectively, in 2014. Substantially all of the international sales of natural gas liquids from the company's producing interests are from operations in Africa, Canada, Indonesia and the United Kingdom.

Refer to "Selected Operating Data," on page FS-11 in Management's Discussion and Analysis of Financial Condition and Results of Operations, for further information on the company's sales volumes of natural gas and natural gas liquids. Refer also to "Delivery Commitments" beginning on page 6 for information related to the company's delivery commitments for the sale of crude oil and natural gas.

Downstream

Refining Operations

At the end of 2014, the company had a refining network capable of processing nearly 2 million barrels of crude oil per day. Operable capacity at December 31, 2014, and daily refinery inputs for 2012 through 2014 for the company and affiliate refineries are summarized in the table below.

Average crude oil distillation capacity utilization during 2014 was 87 percent, compared with 84 percent in 2013. At the U.S. refineries, crude oil distillation capacity utilization averaged 91 percent in 2014, compared with 81 percent in 2013. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 73 percent and 76 percent of Chevron's U.S. refinery inputs in 2014 and 2013, respectively.

At the Pascagoula Refinery, the 25,000 barrels-per-day premium base oil plant began commercial production in third quarter 2014. Elsewhere, work continued during 2014 on projects to improve refinery flexibility, reliability and capability to process lower cost feedstocks. A project to replace the atmospheric distillation column and other related equipment at the Salt Lake City Refinery was completed in mid-2014, resulting in improved plant reliability and feedstock flexibility. At the El Segundo Refinery, a project to replace six end-of-life coke drums was also completed during the year. At the Richmond, California refinery, a modernization project progressed, with certification of the Environmental Impact Report and approval of a conditional use permit by the Richmond City Council in July 2014. The company is now seeking to secure the further necessary approvals to resume construction. In addition, Chevron is evaluating the Hawaii refinery and related assets for possible divestment.

Outside the United States, Caltex Australia Ltd., a 50 percent-owned affiliate, completed the conversion of the Kurnell, Australia, refinery to an import terminal in fourth quarter 2014. During 2014, Singapore Refining Company, Chevron's 50 percent-owned joint venture, initiated construction of a gasoline desulfurization facility and a cogeneration plant. The investment is expected to increase the refinery's capability to produce higher value gasoline and to improve energy efficiency.

Petroleum Refineries: Locations, Capacities and Inputs

Capacities and inputs in thousands of barrels per day			**December 31, 2014**		**Refinery Inputs**	
Locations		**Number**	**Operable Capacity**	**2014**	**2013**	**2012**
Pascagoula	Mississippi	**1**	**330**	**329**	304	335
El Segundo	California	**1**	**269**	**221**	235	265
Richmond	California	**1**	**257**	**229**	153	142
Kapolei	Hawaii	**1**	**54**	**47**	39	46
Salt Lake City	Utah	**1**	**50**	**45**	43	45
Total Consolidated Companies — United States		**5**	**960**	**871**	774	833
Map Ta Phut[1]	Thailand	**1**	**165**	**141**	161	95
Cape Town[2]	South Africa	**1**	**110**	**72**	78	79
Burnaby, B.C.	Canada	**1**	**55**	**49**	42	49
Total Consolidated Companies — International		**3**	**330**	**262**	281	223
Affiliates[1,3]	Various Locations	**5**	**610**	**557**	583	646
Total Including Affiliates — International		**8**	**940**	**819**	864	869
Total Including Affiliates — Worldwide		**13**	**1,900**	**1,690**	1,638	1,702

1 As of June 2012, Star Petroleum Refining Company crude input volumes are reported on a consolidated basis. Prior to June 2012, crude volumes reflect a 64 percent equity interest and are reported in affiliates.

2 Chevron holds a controlling interest in the shares issued by Chevron South Africa (Pty) Limited, which owns the Cape Town Refinery. A consortium of South African partners, along with the employees of Chevron South Africa (Pty) Limited, own preferred shares ultimately convertible to 25 percent equity interest in Chevron South Africa (Pty) Limited.

3 In fourth quarter 2014, Caltex Australia Ltd. completed the conversion of the 68,000-barrel-per-day Kurnell refinery into an import terminal.

Marketing Operations

The company markets petroleum products under the principal brands of “Chevron,” “Texaco” and “Caltex” throughout many parts of the world. The following table identifies the company’s and affiliates’ refined products sales volumes, excluding intercompany sales, for the three years ended December 31, 2014.

Refined Products Sales Volumes

Thousands of barrels per day	2014	2013	2012
United States			
Gasoline	**615**	613	624
Jet Fuel	**222**	215	212
Gas Oil and Kerosene	**217**	195	213
Residual Fuel Oil	**63**	69	68
Other Petroleum Products[1]	**93**	90	94
Total United States	**1,210**	1,182	1,211
International[2]			
Gasoline	**403**	398	412
Jet Fuel	**249**	245	243
Gas Oil and Kerosene	**498**	510	496
Residual Fuel Oil	**162**	179	210
Other Petroleum Products[1]	**189**	197	193
Total International	**1,501**	1,529	1,554
Total Worldwide[2]	**2,711**	2,711	2,765

[1] Principally naphtha, lubricants, asphalt and coke.

[2] Includes share of affiliates’ sales:	**475**	471	522

In the United States, the company markets under the Chevron and Texaco brands. At year-end 2014, the company supplied directly or through retailers and marketers approximately 7,930 Chevron- and Texaco-branded motor vehicle service stations, primarily in the southern and western states. Approximately 380 of these outlets are company-owned or -leased stations.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 8,450 branded service stations, including affiliates. In British Columbia, Canada, the company markets under the Chevron brand. The company markets in Latin America using the Texaco brand. In the Asia-Pacific region, southern Africa and Pakistan, the company uses the Caltex brand. The company also operates through affiliates under various brand names. In South Korea, the company operates through its 50 percent-owned affiliate, GS Caltex, and in Australia through its 50 percent-owned affiliate, Caltex Australia Limited.

Chevron markets commercial aviation fuel at approximately 113 airports worldwide. The company also markets an extensive line of lubricant and coolant products under the product names Havoline, Delo, Ursa, Meropa, Rando, Clarity and Taro in the United States and worldwide under the three brands: Chevron, Texaco and Caltex.

Chemicals Operations

Chevron owns a 50 percent interest in its Chevron Phillips Chemical Company LLC (CPChem) affiliate. CPChem produces olefins, polyolefins and alpha olefins and is a supplier of aromatics and polyethylene pipe, in addition to participating in the specialty chemical and specialty plastics markets. At the end of 2014, CPChem owned or had joint-venture interests in 34 manufacturing facilities and two research and development centers around the world.

In second quarter 2014, CPChem completed commissioning and started commercial operation of a 1-hexene plant with a design capacity of 250,000 metric tons per year at the Cedar Bayou Plant in Baytown, Texas and, in fourth quarter 2014, CPChem began commercial operations of a 90,000 metric-ton-per-year expansion of ethylene production at its Sweeny complex located in Old Ocean, Texas. In early 2014, construction commenced on the U.S. Gulf Coast Petrochemicals Project, which is expected to capitalize on advantaged feedstock sourced from shale gas development in North America. The project includes an ethane cracker with an annual design capacity of 1.5 million metric tons of ethylene to be located at the Cedar Bayou facility and two polyethylene units to be located in Old Ocean, Texas, with a combined annual design capacity of one million metric tons. Start-up is expected in 2017.

Chevron Oronite Company develops, manufactures and markets performance additives for lubricating oils and fuels and conducts research and development for additive component and blended packages. At the end of 2014, the company manufactured, blended or conducted research at 10 locations around the world. In 2014, the company completed expansion projects at its manufacturing facilities in Singapore and Gonfreville, France. In addition, a final investment decision was reached in fourth quarter 2014 to build a carboxylate plant in Singapore, which is expected to be completed in 2017.

Chevron also maintains a role in the petrochemical business through the operations of GS Caltex, a 50 percent-owned affiliate. GS Caltex manufactures aromatics, including benzene, toluene and xylene. These are base chemicals used to produce a range of products, including adhesives, plastics and textile fibers. GS Caltex also produces polypropylene, which is used to make food packaging, laboratory equipment and textiles.

Transportation

Pipelines: Chevron owns and operates a network of crude oil, natural gas, natural gas liquid, refined product and chemical pipelines and other infrastructure assets in the United States. In addition, Chevron operates pipelines for its 50 percent-owned CPChem affiliate. The company also has direct and indirect interests in other U.S. and international pipelines.

During 2014, the company continued to optimize its portfolio of pipeline and infrastructure assets. Net pipeline mileage at the end of 2014 was 5,548, a reduction of 4,524 miles from 2013, mainly due to asset sales. Also in 2014, Chevron completed construction of a 136-mile, 24-inch crude oil pipeline from the Jack/St. Malo deepwater production facility to a platform in Green Canyon Block 19 on the U.S. Gulf of Mexico shelf, where there is an interconnect to pipelines delivering crude oil into Texas and Louisiana. Pipeline operations began with start-up of the production facilities in late 2014.

Refer to pages 13 and 14 in the Upstream section for information on the West African Gas Pipeline, the Baku-Tbilisi-Ceyhan Pipeline, the Western Route Export Pipeline and the Caspian Pipeline Consortium.

Shipping: The company's marine fleet includes both U.S. and foreign-flagged vessels. The U.S.-flagged vessels are engaged primarily in transporting refined products, primarily in the coastal waters of the United States. The foreign-flagged vessels are engaged primarily in transporting crude oil from the Middle East, Southeast Asia, the Black Sea, South America, Mexico and West Africa to ports in the United States, Europe, Australia and Asia, as well as refined products and feedstocks to and from various locations worldwide. In 2014, the company took delivery of three bareboat charter VLCCs and two Pacific Area Lightering vessels.

The company also owns a 16.7 percent interest in each of seven LNG carriers transporting cargoes for the North West Shelf Venture in Australia. In 2014, the company took delivery of two new LNG carriers in support of its developing LNG portfolio.

Other Businesses

Power and Energy Management: The company's power and energy management operation delivers comprehensive commercial, engineering and operational support services to improve power reliability and energy efficiency for Chevron's operations worldwide. The business operates a variety of power assets, including gas-fired cogeneration facilities within Chevron's San Joaquin Valley operations in California, and renewable power facilities in California, New Mexico and Wyoming. The business also manages Chevron's investments in six renewable power projects in California, Arizona and Texas.

Chevron also has major geothermal operations in Indonesia and the Philippines. For additional information on the company's geothermal operations refer to page 15 in the Upstream section.

Research and Technology: Chevron's energy technology organization supports upstream and downstream businesses. The company conducts research, develops and qualifies technology, and provides technical services and competency development. The disciplines cover earth sciences, reservoir and production engineering, drilling and completions, facilities engineering, manufacturing, process technology, catalysis, technical computing and health, environment and safety.

Chevron's information technology organization integrates computing, telecommunications, data management, security and network technology to provide a standardized digital infrastructure to enable Chevron’s global operations and business processes.

Chevron's technology ventures company supports Chevron's upstream and downstream businesses by sourcing and demonstrating emerging technologies and championing their integration into Chevron’s operations. As of the end of 2014, the company continued to source technologies in emerging materials, power systems, production enhancements, renewables, water management, information technologies and advanced biofuels, and to develop options for efficient management of Chevron's carbon footprint. Additionally, in 2014, the company made investments in start-up companies with technologies for pipeline integrity, efficient carbon dioxide capture from flue gas and big data management.

Some of the investments the company makes in the areas described above are in new or unproven technologies and business processes, and ultimate technical or commercial successes are not certain. Refer to Note 25 beginning on FS-59 for a summary of the company's research and development expenses.

Environmental Protection: The company designs, operates and maintains its facilities to avoid potential spills or leaks and to minimize the impact of those that may occur. Chevron requires its facilities and operations to have operating standards and processes and emergency response plans that address all credible and significant risks identified through site-specific risk and impact assessments. Chevron also requires that sufficient resources be available to execute these plans. In the unlikely event that a major spill or leak occurs, Chevron also maintains a Worldwide Emergency Response Team comprised of employees who are trained in various aspects of emergency response, including post-incident remediation.

To complement the company's capabilities, Chevron maintains active membership in international oil spill response cooperatives, including the Marine Spill Response Corporation, which operates in U.S. territorial waters, and Oil Spill Response, Ltd., which operates globally. The company is a founding member of the Marine Well Containment Company, whose primary mission is to expediently deploy containment equipment and systems to capture and contain crude oil in the unlikely event of a future loss of control of a deepwater well in the Gulf of Mexico. In addition, the company is a member of the Subsea Well Response Project (SWRP). SWRP's objective is to further develop the industry's capability to contain and shut in subsea well control incidents in different regions of the world.

Refer to Management's Discussion and Analysis of Financial Condition and Results of Operations on page FS-16 for additional information on environmental matters and their impact on Chevron, and on the company's 2014 environmental expenditures. Refer to page FS-16 and Note 23 on page FS-58 for a discussion of environmental remediation provisions and year-end reserves. Refer also to Item 1A. Risk Factors on pages 22 through 24 for a discussion of greenhouse gas regulation and climate change.

Item 1A. Risk Factors

Chevron is a global energy company with a diversified business portfolio, a strong balance sheet, and a history of generating sufficient cash to pay dividends and fund capital and exploratory expenditures. Nevertheless, some inherent risks could materially impact the company's results of operations or financial condition.

Chevron is exposed to the effects of changing commodity prices: Chevron is primarily in a commodities business that has a history of price volatility. The single largest variable that affects the company's results of operations is the price of crude oil, which can be influenced by general economic conditions, industry inventory levels, production quotas or other actions imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damage and disruptions, competing fuel prices, and geopolitical risks. Chevron accepts the risk of changing commodity prices as part of its business planning process. As such, an investment in the company carries significant exposure to fluctuations in global crude oil prices.

During extended periods of historically low prices for crude oil, the company's upstream earnings, cash flows, and capital and exploratory expenditure programs will be negatively affected, as will its production and proved reserves. Upstream assets may also become impaired. The impact on downstream earnings is dependent upon the supply and demand for refined products and the associated margins on refined product sales.

The scope of Chevron's business will decline if the company does not successfully develop resources: The company is in an extractive business; therefore, if Chevron is not successful in replacing the crude oil and natural gas it produces with good prospects for future production or through acquisitions, the company's business will decline. Creating and maintaining an inventory of projects depends on many factors, including obtaining and renewing rights to explore, develop and produce hydrocarbons; drilling success; ability to bring long-lead-time, capital-intensive projects to completion on budget and on schedule; and efficient and profitable operation of mature properties.

The company's operations could be disrupted by natural or human factors: Chevron operates in both urban areas and remote and sometimes inhospitable regions. The company's operations and facilities are therefore subject to disruption from either natural or human causes beyond its control, including hurricanes, floods and other forms of severe weather, war, civil unrest and other political events, fires, earthquakes, system failures, cyber threats and terrorist acts, any of which could result in suspension of operations or harm to people or the natural environment.

Chevron utilizes comprehensive risk management systems to assess potential physical and other risks to its assets and to plan for their resiliency. While capital investment reviews and decisions involve uncertainty analysis, which incorporates potential ranges of physical risks such as storm severity and frequency, sea level rise, air and water temperature, precipitation, fresh water access, wind speed, and earthquake severity, among other factors, Chevron cannot predict the timing, frequency or severity of such events, any of which could have a material adverse effect on the company's results of operations or financial condition.

The company's operations have inherent risks and hazards that require significant and continuous oversight: Chevron's results depend on its ability to identify and mitigate the risks and hazards inherent to operating in the crude oil and natural gas industry. The company seeks to minimize these operational risks by carefully designing and building its facilities and conducting its operations in a safe and reliable manner. However, failure to manage these risks effectively could result in unexpected incidents, including releases, explosions or mechanical failures resulting in personal injury, loss of life, environmental damage, loss of revenues, legal liability and/or disruption to operations. Chevron has implemented and maintains a system of corporate policies, behaviors and compliance mechanisms to manage safety, health, environmental, reliability and efficiency risks; to verify compliance with applicable laws and policies; and to respond to and learn from unexpected incidents. In certain situations where Chevron is not the operator, the company may have limited influence and control over third parties, which may limit its ability to manage and control such risks.

Chevron's business subjects the company to liability risks from litigation or government action: The company produces, transports, refines and markets materials with potential toxicity, and it purchases, handles and disposes of other potentially toxic materials in the course of its business. Chevron's operations also produce byproducts, which may be considered pollutants. Often these operations are conducted through joint ventures over which the company may have limited influence and control. Any of these activities could result in liability or significant delays in operations arising from private litigation or government action, either as a result of an accidental, unlawful discharge or as a result of new conclusions about the effects of the company's operations on human health or the environment. In addition, to the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to the company's causation of or contribution to the asserted damage, or to other mitigating factors.

For information concerning some of the litigation in which the company is involved, including information relating to Ecuador matters, see Note 15 to the Consolidated Financial Statements, beginning on page FS-42.

The company does not insure against all potential losses, which could result in significant financial exposure: The company does not have commercial insurance or third-party indemnities to fully cover all operational risks or potential liability in the event of a significant incident or series of incidents causing catastrophic loss. As a result, the company is, to a substantial extent, self-insured for such events. The company relies on existing liquidity, financial resources and borrowing capacity to meet short-term obligations that would arise from such an event or series of events. The occurrence of a significant incident or unforeseen liability for which the company is not fully insured or for which insurance recovery is significantly delayed could have a material adverse effect on the company's results of operations or financial condition.

Political instability and significant changes in the regulatory environment could harm Chevron's business: The company's operations, particularly exploration and production, can be affected by changing economic, regulatory and political environments in the various countries in which it operates. As has occurred in the past, actions could be taken by governments to increase public ownership of the company's partially or wholly owned businesses or to impose additional taxes or royalties. In certain locations, governments have proposed or imposed restrictions on the company's operations, export and exchange controls, burdensome taxes, and public disclosure requirements that might harm the company's competitiveness or relations with other governments or third parties. In other countries, political conditions have existed that may threaten the safety of employees and the company's continued presence in those countries, and internal unrest, acts of violence or strained relations between a government and the company or other governments may adversely affect the company's operations. Those developments have, at times, significantly affected the company's related operations and results and are carefully considered by management when evaluating the level of current and future activity in such countries. In addition, changes in national or state environmental regulations, including those related to the use of hydraulic fracturing, could adversely affect the company's current or anticipated future operations and profitability.

Regulation of greenhouse gas emissions could increase Chevron's operational costs and reduce demand for Chevron's products: Continued political attention to issues concerning climate change, the role of human activity in it, and potential mitigation through regulation could have a material impact on the company's operations and financial results.

International agreements and national or regional legislation and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. These and other greenhouse gas emissions-related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted in each jurisdiction, the company's activities in it and market conditions. Greenhouse gas emissions that could be regulated include those arising from the company's exploration and production of crude oil and natural gas; the upgrading of production from oil sands into synthetic oil; power generation; the conversion of crude oil and natural gas into refined products; the processing, liquefaction and regasification of natural gas; the transportation of crude oil, natural gas and related products and consumers' or customers' use of the company's products. Some of these activities, such as consumers' and customers' use of the company's products, as well as actions taken by the company's competitors in response to such laws and regulations, are beyond the company's control.

The effect of regulation on the company's financial performance will depend on a number of factors including, among others, the sectors covered, the greenhouse gas emissions reductions required by law, the extent to which Chevron would be entitled to receive emission allowance allocations or would need to purchase compliance instruments on the open market or through auctions, the price and availability of emission allowances and credits, and the impact of legislation or other regulation on the company's ability to recover the costs incurred through the pricing of the company's products. Material price increases or incentives to conserve or use alternative energy sources could reduce demand for products the company currently sells and adversely affect the company's sales volumes, revenues and margins.

Changes in management's estimates and assumptions may have a material impact on the company's consolidated financial statements and financial or operational performance in any given period: In preparing the company's periodic reports under the Securities Exchange Act of 1934, including its financial statements, Chevron's management is required under applicable rules and regulations to make estimates and assumptions as of a specified date. These estimates and assumptions are based on management's best estimates and experience as of that date and are subject to substantial risk and uncertainty. Materially different results may occur as circumstances change and additional information becomes known. Areas requiring significant estimates and assumptions by management include measurement of benefit obligations for pension and other postretirement benefit plans; estimates of crude oil and natural gas recoverable reserves; accruals for estimated liabilities, including litigation reserves; and impairments to property, plant and equipment. Changes in estimates or assumptions or the information underlying the assumptions, such as changes in the company's business plans, general market conditions or changes in commodity prices, could affect reported amounts of assets, liabilities or expenses.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and character of the company's crude oil and natural gas properties and its refining, marketing, transportation and chemicals facilities are described on page 3 under Item 1. Business. Information required by Subpart 1200 of Regulation S-K ("Disclosure by Registrants Engaged in Oil and Gas Producing Activities") is also contained in Item 1 and in Tables I through VII on pages FS-61 through FS-71. Note 14, "Properties, Plant and Equipment," to the company's financial statements is on page FS-41.

Item 3. Legal Proceedings

Ecuador: Information related to Ecuador matters is included in Note 15 to the Consolidated Financial Statements under the heading Ecuador, beginning on page FS-42.

Certain Governmental Proceedings: As previously disclosed in the Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, on August 6, 2012, a piping failure and fire occurred at the Chevron U.S.A. Inc. refinery in Richmond, California. Various federal, state, and local agencies initiated investigations as a result of the incident. Based on its civil investigation, the United States Environmental Protection Agency (EPA) issued a Finding of Violations (FOV) to Chevron on December 17, 2013, which includes 62 findings of alleged noncompliance at the refinery. The majority of these findings relate to the August 2012 fire and alleged violations of chemical-accident-prevention laws, but the FOV also addresses a number of release-reporting issues, some of which are unrelated to the fire. Resolution of the alleged violations may result in the payment of a civil penalty of $100,000 or more.

As previously disclosed in the Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in July 2009, the Hawaii Department of Health (DOH) alleged that Chevron is obligated to pay stipulated civil penalties in conjunction with commitments Chevron undertook to install and operate certain air emission control equipment at its Hawaii Refinery pursuant to a Clean Air Act settlement with the United States EPA and the DOH. The company has disputed many of the allegations. Resolution of the alleged violations may result in the payment of a civil penalty of $100,000 or more.

As initially disclosed in the Annual Report on Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, the State of New Mexico provided to Chevron a Notice of Violation on December 11, 2013, alleging that the flaring of fuel gas that occurred during periodic compressor purging events at the Chevron Buckeye CO2 plant resulted in hourly air emissions during these events in excess of the plant permit limits and alleging that the company had failed to timely report these excess emissions. The company has reached a settlement agreement with the State of New Mexico and paid a civil penalty of less than $100,000 to resolve the alleged violation.

As initially disclosed in the Quarterly Report on Form 10-Q for the period ended March 31, 2014, filed May 2, 2014, a fire was reported on February 11, 2014, at Chevron Appalachia, LLC's Lanco 7H well located in Dunkard Township, Greene County, Pennsylvania. The Pennsylvania Department of Environmental Protection (PA DEP) and the Occupational Safety and Health Administration of the United States (OSHA) initiated investigations as a result of the incident. Based on its civil investigation to date, the PA DEP has issued Chevron a Notice of Violation alleging nine separate incidents of noncompliance. Resolution of the alleged violations may result in the payment of a civil penalty of $100,000 or more.

Item 4. Mine Safety Disclosures

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 C.F.R. § 229.104) is included in Exhibit 95 of this Annual Report on Form 10-K.

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The information on Chevron's common stock market prices, dividends, principal exchanges on which the stock is traded and number of stockholders of record is contained in the Quarterly Results and Stock Market Data tabulations, on page FS-20.

Chevron Corporation Issuer Purchases of Equity Securities for Quarter Ended December 31, 2014

Period	Total Number of Shares Purchased [1,2]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares That May Yet be Purchased Under the Program[2]
Oct. 1 – Oct. 31, 2014	3,951,297	$114.97	3,951,111	—
Nov. 1 – Nov. 30, 2014	3,308,849	117.00	3,307,758	—
Dec. 1 – Dec. 31, 2014	3,733,530	109.48	3,733,530	—
Total Oct. 1 – Dec. 31, 2014	**10,993,676**	**$113.72**	**10,992,399**	**—**

1 Includes common shares repurchased from company employees for required personal income tax withholdings on the exercise of the stock options and shares delivered or attested to in satisfaction of the exercise price by holders of the employee stock options. The options were issued to and exercised by management under Chevron long-term incentive plans and Unocal stock option plans.

2 In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits, under which common shares would be acquired by the company through open market purchases or in negotiated transactions at prevailing prices, as permitted by securities laws and other legal requirements and subject to market conditions and other factors. As of December 31, 2014, 180,886,291 shares had been acquired under this program (some pursuant to a Rule 10b5-1 plan and some pursuant to accelerated share repurchase plans) for $20 billion at an average price of approximately $111 per share. The company does not plan to acquire any shares under the program in 2015.

Item 6. Selected Financial Data

The selected financial data for years 2010 through 2014 are presented on page FS-60.

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

The index to Management's Discussion and Analysis of Financial Condition and Results of Operations, Consolidated Financial Statements and Supplementary Data is presented on page FS-1.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The company's discussion of interest rate, foreign currency and commodity price market risk is contained in Management's Discussion and Analysis of Financial Condition and Results of Operations — "Financial and Derivative Instrument Market Risk," on page FS-15 and in Note 10 to the Consolidated Financial Statements, "Financial and Derivative Instruments," beginning on page FS-35.

Item 8. Financial Statements and Supplementary Data

The index to Management's Discussion and Analysis, Consolidated Financial Statements and Supplementary Data is presented on page FS-1.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures: The company's management has evaluated, with the participation of the

Chief Executive Officer and the Chief Financial Officer, the effectiveness of the company's disclosure controls and procedures (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")) as of the end of the period covered by this report. Based on this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the company's disclosure controls and procedures were effective as of December 31, 2014.

(b) 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 the Chief Financial Officer, conducted an evaluation of the effectiveness of the company's internal control over financial reporting based on the *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the results of this evaluation, the company's management concluded that internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of the company's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included on page FS-22.

(c) Changes in Internal Control Over Financial Reporting: During the quarter ended December 31, 2014, there were no changes in the company's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

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

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant at February 20, 2015

Members of the Corporation's Executive Committee are the Executive Officers of the Corporation:

Name	Age	Current and Prior Positions (up to five years)	Current Areas of Responsibility
J.S. Watson	58	Chairman of the Board and Chief Executive Officer (since 2010)	Chairman of the Board and Chief Executive Officer
G.L. Kirkland	64	Vice Chairman of the Board and Executive Vice President (since 2010)	Vice Chairman of the Board and Executive Vice President
M.K. Wirth	54	Executive Vice President (since 2006)	Worldwide Refining, Marketing and Lubricants; Chemicals
J.C. Geagea	55	Senior Vice President, Technology, Projects and Services (since 2014) Corporate Vice President and President, Gas and Midstream (2012 through 2013) Managing Director, Asia South Business Unit (2008 through 2011)	Technology; Health, Environment and Safety; Project Resources Company; Procurement
J.W. Johnson	55	Senior Vice President, Upstream (since 2014) President, Europe, Eurasia and Middle East Exploration and Production (2011 through 2013) Managing Director, Eurasia Business Unit (2008 to 2011)	Worldwide Exploration and Production Activities
P.R. Breber	50	Corporate Vice President and President, Gas and Midstream (since 2014) Managing Director, Asia South Business Unit (2012 through 2013) Deputy Managing Director, Asia South Business Unit (2011) Vice President and Treasurer (2009 to 2011)	Worldwide Natural Gas Commercialization; Supply and Trading Activities, including Natural Gas Trading; Shipping; Pipeline; and Power and Energy Management
P.E. Yarrington	58	Vice President and Chief Financial Officer (since 2009)	Finance
R.H. Pate	52	Vice President and General Counsel (since 2009)	Law, Governance and Compliance

The information about directors required by Item 401 (a), (d), (e) and (f) of Regulation S-K and contained under the heading

“Election of Directors” in the Notice of the 2015 Annual Meeting and 2015 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934 (the “Exchange Act”), in connection with the company’s 2015 Annual Meeting of Stockholders (the “2015 Proxy Statement”), is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 405 of Regulation S-K and contained under the heading “Stock Ownership Information — Section 16(a) Beneficial Ownership Reporting Compliance” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 406 of Regulation S-K and contained under the heading “Corporate Governance — Business Conduct and Ethics Code” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(d)(4) and (5) of Regulation S-K and contained under the heading “Corporate Governance — Board Committees” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

There were no changes to the process by which stockholders may recommend nominees to the Board of Directors during the last fiscal year.

Item 11. Executive Compensation

The information required by Item 402 of Regulation S-K and contained under the headings “Executive Compensation” and “Director Compensation” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(e)(4) of Regulation S-K and contained under the heading “Corporate Governance — Board Committees” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(e)(5) of Regulation S-K and contained under the heading “Corporate Governance — Management Compensation Committee Report” in the 2015 Proxy Statement is incorporated herein by reference into this Annual Report on Form 10-K. Pursuant to the rules and regulations of the SEC under the Exchange Act, the information under such caption incorporated by reference from the 2015 Proxy Statement shall not be deemed to be “soliciting material,” or to be “filed” with the Commission, or subject to Regulation 14A or 14C or the liabilities of Section 18 of the Exchange Act nor shall it be deemed incorporated by reference into any filing under the Securities Act of 1933.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by Item 403 of Regulation S-K and contained under the heading “Stock Ownership Information — Security Ownership of Certain Beneficial Owners and Management” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 201(d) of Regulation S-K and contained under the heading “Equity Compensation Plan Information” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by Item 404 of Regulation S-K and contained under the heading “Corporate Governance — Related Person Transactions” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

The information required by Item 407(a) of Regulation S-K and contained under the heading “Corporate Governance — Director Independence” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

Item 14. Principal Accounting Fees and Services

The information required by Item 9(e) of Schedule 14A and contained under the heading “Board Proposal to Ratify the Appointment of the Independent Registered Public Accounting Firm” in the 2015 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this report:

(1) Financial Statements:

(2) Financial Statement Schedules:

Included below is Schedule II - Valuation and Qualifying Accounts.

(3) Exhibits:

The Exhibit Index on pages E-1 through E-2 lists the exhibits that are filed as part of this report.

Schedule II — Valuation And Qualifying Accounts

	Year ended December 31		
Millions of Dollars	**2014**	2013	2012
Employee Termination Benefits			
Balance at January 1	**$ 14**	$ 30	$ 63
Additions (reductions) charged to expense	**53**	(6)	3
Payments	**(18)**	(10)	(36)
Balance at December 31	**$ 49**	$ 14	$ 30
Allowance for Doubtful Accounts			
Balance at January 1	**$ 95**	$ 155	$ 167
Additions (reductions) to expense	**119**	1	(4)
Bad debt write-offs	**(20)**	(61)	(8)
Balance at December 31	**$ 194**	$ 95	$ 155
Deferred Income Tax Valuation Allowance*			
Balance at January 1	**$ 17,171**	$ 15,443	$ 11,096
Additions to deferred income tax expense	**1,192**	2,665	5,471
Reduction of deferred income tax expense	**(2,071)**	(937)	(1,124)
Balance at December 31	**$ 16,292**	$ 17,171	$ 15,443

* See also Note 16 to the Consolidated Financial Statements, beginning on page FS-45.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 20th day of February, 2015.

Chevron Corporation

By /s/ JOHN S. WATSON

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on the 20th day of February, 2015.

Principal Executive Officers
(and Directors)

/s/JOHN S. WATSON
John S. Watson, Chairman of the
Board and Chief Executive Officer

/s/GEORGE L. KIRKLAND
George L. Kirkland, Vice Chairman
of the Board

Principal Financial Officer

/s/PATRICIA E. YARRINGTON
Patricia E. Yarrington, Vice President
and Chief Financial Officer

Principal Accounting Officer

/s/MATTHEW J. FOEHR
Matthew J. Foehr, Vice President
and Comptroller

*By: /s/LYDIA I. BEEBE
Lydia I. Beebe,
Attorney-in-Fact

Directors

ALEXANDER B. CUMMINGS, JR.*
Alexander B. Cummings, Jr.

LINNET F. DEILY*
Linnet F. Deily

ROBERT E. DENHAM*
Robert E. Denham

ALICE P. GAST*
Alice P. Gast

ENRIQUE HERNANDEZ, JR.*
Enrique Hernandez, Jr.

JON M. HUNTSMAN, JR.*
Jon M. Huntsman, Jr.

CHARLES W. MOORMAN*
Charles W. Moorman

KEVIN W. SHARER*
Kevin W. Sharer

JOHN G. STUMPF*
John G. Stumpf

RONALD D. SUGAR*
Ronald D. Sugar

INGE G. THULIN*
Inge G. Thulin

CARL WARE*
Carl Ware

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Management's Discussion and Analysis of Financial Condition and Results of Operations

Key Financial Results

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

Earnings by Major Operating Area

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

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

Refer to the “Results of Operations” section beginning on page FS-7 for a discussion of financial results by major operating area for the three years ended December 31, 2014.

Business Environment and Outlook

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

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

Refer to the "Cautionary Statement Relevant to Forward-Looking Information" on page 2 and to "Risk Factors" in Part I, Item 1A, on pages 22 through 24 for a discussion of some of the inherent risks that could materially impact the company's results of operations or financial condition.

The company continually evaluates opportunities to dispose of assets that are not expected to provide sufficient long-term value or to acquire assets or operations complementary to its asset base to help augment the company’s financial performance and growth.

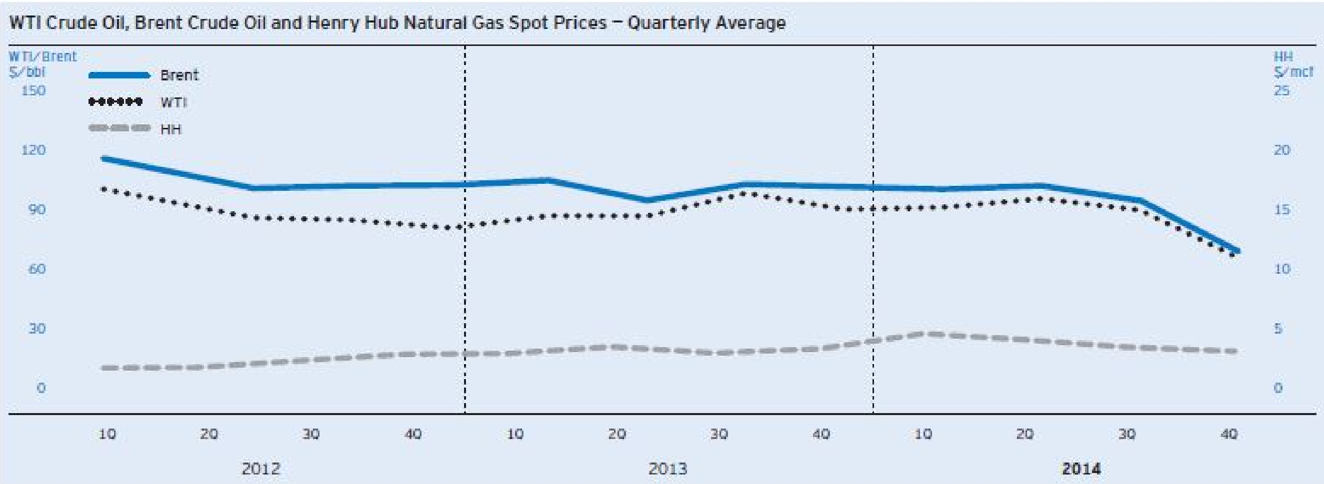
Refer to the “Results of Operations” section beginning on page FS-7 for discussions of net gains on asset sales during 2014. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

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

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

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

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



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

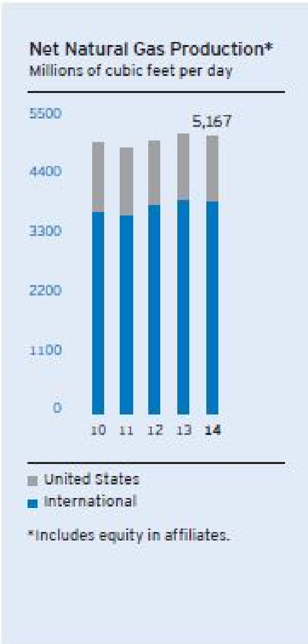
The WTI price averaged $93 per barrel for the full-year 2014, compared to $98 in 2013. As of mid-February 2015, the WTI price was $53 per barrel. WTI traded at a discount to Brent throughout 2014 due to high inventories and excess crude supply in the U.S. market.

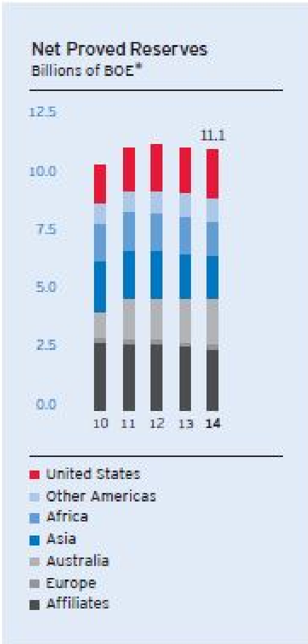
A differential in crude oil prices exists between high-quality (high-gravity, low-sulfur) crudes and those of lower quality (low-gravity, high-sulfur). The amount of the differential in any period is associated with the supply of heavy crude versus the demand, which is a function of the capacity of refineries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

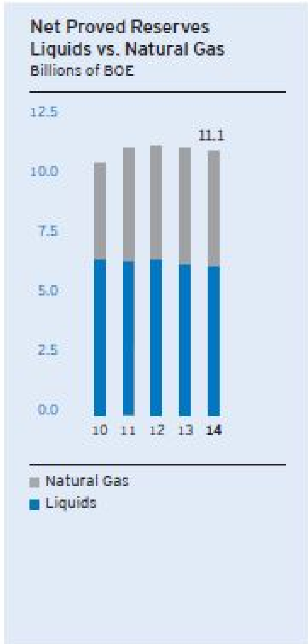
Chevron produces or shares in the production of heavy crude oil in California, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom sector of the North Sea. (See page FS-11 for the company's average U.S. and international crude oil realizations.)

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

Outside the United States, price changes for natural gas depend on a wide range of supply, demand, regulatory and commercial factors. In some locations, Chevron is investing in long-term projects to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets. The company's contract prices for liquefied natural gas (LNG) are typically linked to crude oil prices. Chevron's international natural gas realizations averaged $5.78 per MCF during 2014, compared with $5.91 per MCF during 2013. (See page FS-11 for the company's average natural gas realizations for the U.S. and international regions.)







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

The company estimates that oil-equivalent production in 2015 will be flat to 3 percent growth compared to 2014. This estimate is subject to many factors and uncertainties, including the duration of the low price environment that began in second-half 2014; quotas that may be imposed by OPEC; price effects on entitlement volumes; changes in fiscal terms or restrictions on the scope of company operations; delays in construction, start-up or ramp-up of projects; fluctuations in demand for natural gas in various markets; weather conditions that may shut in production; civil unrest; changing geopolitics; delays in completion of maintenance turnarounds; greater-than-expected declines in production from mature fields; or other disruptions to operations. The outlook for future production levels is also affected by the size and number of economic investment opportunities and, for new, large-scale projects, the time lag between initial exploration and the beginning of production. Investments in upstream projects generally begin well in advance of the start of the associated crude oil and natural gas production. A significant majority of Chevron’s upstream investment is made outside the United States.

Net proved reserves for consolidated companies and affiliated companies totaled 11.1 billion barrels of oil equivalent at year-end 2014, a decrease of 1 percent from year-end 2013. The reserve replacement ratio in 2014 was 89 percent. Refer to Table V beginning on page FS-65 for a tabulation of the company’s proved net oil and gas reserves by geographic area, at the beginning of 2012 and each year-end from 2012 through 2014, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2014.

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

Refer to the “Results of Operations” section on pages FS-7 through FS-9 for additional discussion of the company’s upstream business.

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

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

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

Refer to the “Results of Operations” section on pages FS-7 through FS-9 for additional discussion of the company’s downstream operations.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations

Operating Developments

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

Upstream

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

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

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

Bangladesh Announced first gas from the Bibiyana Expansion Project.

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

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

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

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

Myanmar Announced the acquisition of offshore acreage.

New Zealand Announced the acquisition of three offshore blocks.

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

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

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

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

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

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

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

Downstream

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

Singapore Completed expansion project at the additives plant in Singapore.

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

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

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

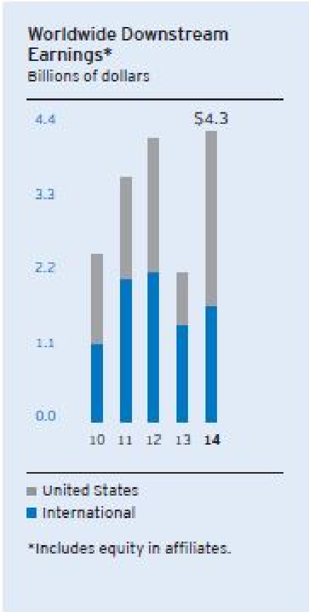
Other

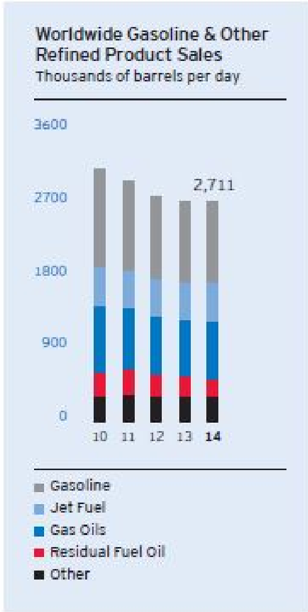
Common Stock Dividends The quarterly common stock dividend was increased by 7.0 percent in April 2014 to $1.07 per common share, making 2014 the 27th consecutive year that the company increased its annual dividend payout.

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

Results of Operations

The following section presents the results of operations and variances on an after-tax basis for the company's business segments – Upstream and Downstream – as well as for "All Other." Earnings are also presented for the U.S. and international geographic areas of the Upstream and Downstream business segments. Refer to Note 12, beginning on page FS-37, 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 FS-2 through FS-5.





U.S. Upstream

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

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

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

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

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

The net liquids component of oil-equivalent production for 2014 averaged 456,000 barrels per day, up 2 percent from 2013 and largely unchanged from 2012. Net natural gas production averaged about 1.3 billion cubic feet per day in 2014, largely unchanged from 2013 and up 4 percent from 2012. Refer to the "Selected Operating Data" table on page FS-11 for a three-year comparative of production volumes in the United States.

International Upstream

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

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

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

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

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

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

Refer to the "Selected Operating Data" table, on page FS-11, for a three-year comparative of international production volumes.

U.S. Downstream

Millions of dollars		**2014**		2013		2012
Earnings	**$**	**2,637**	$	787	$	2,048

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

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

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

Refer to the "Selected Operating Data" table on page FS-11 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

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

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

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

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

Refer to the "Selected Operating Data" table, on page FS-11, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

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

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

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

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2014**	2013	2012
Sales and other operating revenues	**$ 200,494**	$ 220,156	$ 230,590

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

Millions of dollars	**2014**	2013	2012
Income from equity affiliates	**$ 7,098**	$ 7,527	$ 6,889

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

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

Refer to Note 13, beginning on page FS-40, for a discussion of Chevron's investments in affiliated companies.

Millions of dollars		**2014**		2013		2012
Other income	**$**	**4,378**	$	1,165	$	4,430

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

Millions of dollars		**2014**		2013		2012
Purchased crude oil and products	**$**	**119,671**	$	134,696	$	140,766

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

Millions of dollars		**2014**		2013		2012
Operating, selling, general and administrative expenses	**$**	**29,779**	$	29,137	$	27,294

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

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

Millions of dollars		**2014**		2013		2012
Exploration expense	**$**	**1,985**	$	1,861	$	1,728

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

Millions of dollars		**2014**		2013		2012
Depreciation, depletion and amortization	**$**	**16,793**	$	14,186	$	13,413

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

Millions of dollars		**2014**		2013		2012
Taxes other than on income	**$**	**12,540**	$	13,063	$	12,376

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

Millions of dollars		**2014**		2013		2012
Income tax expense	**$**	**11,892**	$	14,308	$	19,996

Effective income tax rates were 38 percent in 2014, 40 percent in 2013 and 43 percent in 2012. The decrease in the effective tax rate between 2014 and 2013 primarily resulted from the impact of changes in jurisdictional mix and equity earnings, and the tax effects related to the 2014 sale of interests in Chad and Cameroon, partially offset by other one-time and ongoing tax charges.

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

Selected Operating Data[1,2]

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

[1] Includes company share of equity affiliates.

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

[3] Includes natural gas consumed in operations (MMCFPD):

United States	**71**	72	65
International[8]	**452**	458	457

[4] Includes net production of synthetic oil:

Canada	**43**	43	43
Venezuela affiliate	**31**	25	17

5 Includes branded and unbranded gasoline.

6 Includes sales of affiliates (MBPD):	**475**	471	522

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

8 2013 conforms to 2014 presentation.

Liquidity and Capital Resources

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

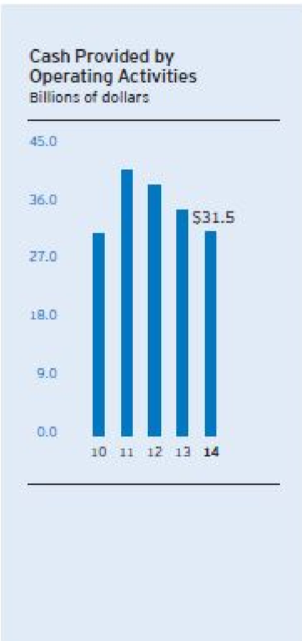
Restricted cash of $1.5 billion and $1.2 billion at December 31, 2014 and 2013, respectively, was held in cash and short-term marketable securities and recorded as “Deferred charges and other assets” on the Consolidated Balance Sheet. These amounts are generally associated with tax payments, upstream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

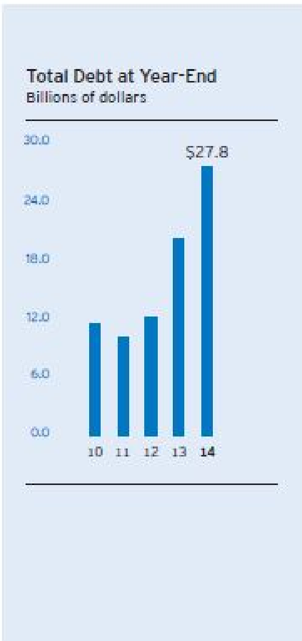
Dividends Dividends paid to common stockholders were $7.9 billion in 2014, $7.5 billion in 2013 and $6.8 billion in 2012. In April 2014, the company increased its quarterly dividend by 7 percent to $1.07 per common share.

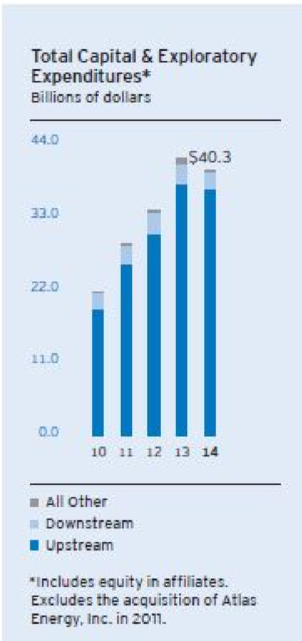
Debt and Capital Lease Obligations Total debt and capital lease obligations were $27.8 billion at December 31, 2014, up from $20.4 billion at year-end 2013.

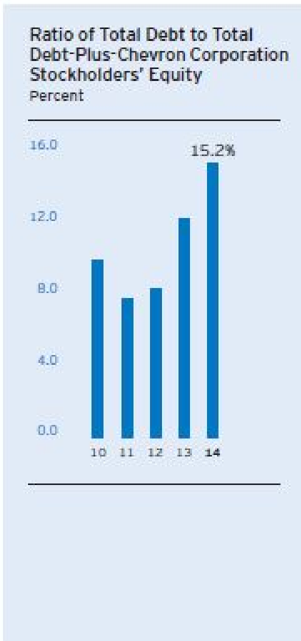
The $7.4 billion increase in total debt and capital lease obligations during 2014 was primarily due to funding the company’s capital investment program, which included several large projects in the construction phase. The company completed a $4 billion bond issuance in November 2014, timed in part to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

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









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

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

Committed Credit Facilities Information related to committed credit facilities is included in Note 18 to the Consolidated Financial Statements, Short-Term Debt, on page FS-49.

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

Capital and Exploratory Expenditures

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

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

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

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

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

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

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

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

Pension Obligations Information related to pension plan contributions is included on page FS-56 in Note 22 to the Consolidated Financial Statements under the heading "Cash Contributions and Benefit Payments."

Financial Ratios

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

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

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

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

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

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

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

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

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 22 beginning on page FS-52.

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

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

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

Direct Guarantees

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

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

Indemnifications Information related to indemnifications is included on page FS-57 in Note 23 to the Consolidated Financial Statements under the heading "Indemnifications."

Financial and Derivative Instrument Market Risk

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

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

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

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

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

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

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

Transactions With Related Parties

Chevron enters into a number of business arrangements with related parties, principally its equity affiliates. These arrangements include long-term supply or offtake agreements and long-term purchase agreements. Refer to "Other Information" in Note 13 of the Consolidated Financial Statements, page FS-41, 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 FS-42 in Note 15 to the Consolidated Financial Statements under the heading "MTBE."

Ecuador Information related to Ecuador matters is included in Note 15 to the Consolidated Financial Statements under the heading

“Ecuador,” beginning on page FS-42.

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		**2014**		2013		2012
Balance at January 1	**$**	**1,456**	$	1,403	$	1,404
Net Additions		**636**		488		428
Expenditures		**(409)**		(435)		(429)
Balance at December 31	**$**	**1,683**	$	1,456	$	1,403

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

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

Refer to the discussion below for additional information on environmental matters and their impact on Chevron, and on the company's 2014 environmental expenditures. Refer to Note 23 on pages FS-57 through FS-59 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 24 on page FS-59 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 20 to the Consolidated Financial Statements, Accounting for Suspended Exploratory Wells, beginning on page FS-49.

Income Taxes Information related to income tax contingencies is included on pages FS-45 through FS-48 in Note 16 and page FS-57 in Note 22 to the Consolidated Financial Statements under the heading “Income Taxes.”

Other Contingencies Information related to other contingencies is included on page FS-58 in Note 23 to the Consolidated Financial Statements under the heading “Other Contingencies.”

Environmental Matters

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

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

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

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

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

Critical Accounting Estimates and Assumptions

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

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

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

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

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

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

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

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

Refer to Table V, “Reserve Quantity Information,” beginning on page FS-65, for the changes in proved reserve estimates for the three years ending December 31, 2014, and to Table VII, “Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves” on page FS-71 for estimates of proved reserve values for each of the three years ended December 31, 2014.

This Oil and Gas Reserves commentary should be read in conjunction with the Properties, Plant and Equipment section of Note 1 to the Consolidated Financial Statements, beginning on page FS-28, 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 FS-34 and to the section on Properties, Plant and Equipment in Note 1, "Summary of Significant Accounting Policies," beginning on page FS-28.

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

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

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

Asset Retirement Obligations In the determination of fair value for an asset retirement obligation (ARO), the company uses various assumptions and judgments, including such factors as the existence of a legal obligation, estimated amounts and timing of settlements, discount and inflation rates, and the expected impact of advances in technology and process improvements. A sensitivity analysis of the ARO impact on earnings for 2014 is not practicable, given the broad range of the company's long-lived assets and the number of assumptions involved in the estimates. That is, favorable changes to some assumptions would have reduced estimated future obligations, thereby lowering accretion expense and amortization costs, whereas unfavorable changes would have the opposite effect. Refer to Note 24 on page FS-59 for additional discussions on asset retirement obligations.

Pension and Other Postretirement Benefit Plans Note 22, beginning on page FS-52, includes information on the funded status of the company's pension and other postretirement benefit (OPEB) plans reflected on the Consolidated Balance Sheet; the components of pension and OPEB expense reflected on the Consolidated Statement of Income; and the related underlying assumptions.

The determination of pension plan expense and obligations is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. Critical assumptions in determining expense and obligations for OPEB plans, which provide for certain health care and life insurance benefits for qualifying retired employees and which are not funded, are the discount rate and the assumed health care cost-trend rates. Information related to the Company's processes to develop these assumptions is included on page FS-54 in Note 22 under the relevant headings. Actual rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

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

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

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

For the company's OPEB plans, expense for 2014 was $219 million, and the total liability, which reflected the unfunded status of the plans at the end of 2014, was $3.7 billion. For the main U.S. OPEB plan, the company used a 4.7 percent discount rate to measure expense in 2014, and a 4.1 percent discount rate to measure the benefit obligations at December 31, 2014. Discount rate changes, similar to those used in the pension sensitivity analysis, resulted in an immaterial impact on 2014 OPEB expense and OPEB liabilities at the end of 2014. For information on the sensitivity of the health care cost-trend rate, refer to FS-54 in Note 22 under the heading "Other Benefit Assumptions."

Differences between the various assumptions used to determine expense and the funded status of each plan and actual experience are included in actuarial gain/loss. Refer to page FS-53 in Note 22 for a description of the method used to amortize the $7.2 billion of before-tax actuarial losses recorded by the company as of December 31, 2014, and an estimate of the costs to be recognized in expense during 2015. In addition, information related to company contributions is included on Page FS-56 in Note 22 under the heading "Cash Contributions and Benefit Payments."

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

Under the accounting rules, a liability is generally recorded for these types of contingencies if management determines the loss to be both probable and estimable. The company generally reports these losses as "Operating expenses" or "Selling, general and administrative expenses” on the Consolidated Statement of Income. An exception to this handling is for income tax matters, for which benefits are recognized only if management determines the tax position is “more likely than not” (i.e., likelihood greater than 50 percent) to be allowed by the tax jurisdiction. For additional discussion of income tax uncertainties, refer to Note 23 beginning on page FS-57. Refer also to the business segment discussions elsewhere in this section for the effect on earnings from losses associated with certain litigation, environmental remediation and tax matters for the three years ended December 31, 2014.

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

New Accounting Standards

Refer to Note 19, on page FS-49 in the Notes to Consolidated Financial Statements, for information regarding new accounting standards.

Quarterly Results and Stock Market Data

Unaudited

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

[2] Intraday price.

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

Management’s Responsibility for Financial Statements

To the Stockholders of Chevron Corporation

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

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

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

Management’s Report on Internal Control Over Financial Reporting

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

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

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

/s/ JOHN S. WATSON	/s/ PATRICIA E. YARRINGTON	/s/ MATTHEW J. FOEHR
John S. Watson Chairman of the Board and Chief Executive Officer	Patricia E. Yarrington Vice President and Chief Financial Officer	Matthew J. Foehr Vice President and Comptroller

February 20, 2015

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income, comprehensive income, equity and of cash flows present fairly, in all material respects, the financial position of Chevron Corporation and its subsidiaries at December 31, 2014, and December 31, 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements 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.

/s/ PRICEWATERHOUSE COOPERS LLP

San Francisco, California

February 20, 2015

Consolidated Statement of Income

Millions of dollars, except per-share amounts

	Year ended December 31		
	2014	2013	2012
Revenues and Other Income			
Sales and other operating revenues*	**$ 200,494**	$ 220,156	$ 230,590
Income from equity affiliates	**7,098**	7,527	6,889
Other income	**4,378**	1,165	4,430
Total Revenues and Other Income	**211,970**	228,848	241,909

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

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2014	2013	2012
Net Income	**$ 19,310**	$ 21,597	$ 26,336
Currency translation adjustment			
Unrealized net change arising during period	**(73)**	42	23
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	**(2)**	(7)	1

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

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

Millions of dollars, except per-share amount

	At December 31	
	2014	2013
Assets		

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

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Millions of dollars

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

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

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

Total Chevron Corporation Stockholders' Equity at December 31	**$ 155,028**	$ 149,113	$ 136,524
Noncontrolling Interests	**$ 1,163**	$ 1,314	$ 1,308
Total Equity	**$ 156,191**	$ 150,427	$ 137,832

See accompanying Notes to the Consolidated Financial Statements.

Note 1

Summary of Significant Accounting Policies

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

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

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

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

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

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

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

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

Costs also are capitalized for exploratory wells that have found crude oil and natural gas reserves even if the reserves cannot be classified as proved when the drilling is completed, provided the exploratory well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project. All other exploratory wells and costs are expensed. Refer to Note 20, beginning on page FS-49, for additional discussion of accounting for suspended exploratory well costs.

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

Long-lived assets that are held for sale are evaluated for possible impairment by comparing the carrying value of the asset with its fair value less the cost to sell. If the net book value exceeds the fair value less cost to sell, the asset is considered impaired and adjusted to the lower value. Refer to Note 9, beginning on page FS-34, 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 FS-59, 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 FS-59, 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 FS-23. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another (including buy/sell arrangements) are combined and recorded on a net basis and reported in "Purchased crude oil and products" on the Consolidated Statement of Income.

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

Note 2

Changes in Accumulated Other Comprehensive Losses

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

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

1 All amounts are net of tax.

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

Note 3

Noncontrolling Interests

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

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

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

Note 4

Information Relating to the Consolidated Statement of Cash Flows

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

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

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

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

The Consolidated Statement of Cash Flows excludes changes to the Consolidated Balance Sheet that did not affect cash. The 2012 period excludes the effects of $800 of proceeds to be received in future periods for the sale of an equity interest in the Wheatstone Project, of which $164 has been received as of December 31, 2014. "Capital expenditures" in the 2012 period excludes a $1,850 increase in "Properties, plant and equipment" related to an upstream asset exchange in Australia. Refer also to Note 24, on page FS-59, for a discussion of revisions to the company's AROs that also did not involve cash receipts or payments for the three years ending December 31, 2014.

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

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

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

Note 5
Equity

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

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

Note 6
Lease Commitments

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

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

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

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

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

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

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

Note 7

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

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

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

	2014	2013
Current assets	**$ 13,724**	$ 17,626
Other assets	**62,195**	57,288
Current liabilities	**16,191**	17,486
Other liabilities	**30,175**	28,119
Total CUSA net equity	**$ 29,553**	$ 29,309

Memo: Total debt	**$**	**14,473**	$	14,482

Note 8

Summarized Financial Data – Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 13, beginning on page FS-40, for a discussion of TCO operations. Summarized financial information for 100 percent of TCO is presented in the table below:

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

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

Note 9

Fair Value Measurements

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

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

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

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

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

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

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

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

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

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

Note 10

Financial and Derivative Instruments

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Note 11

Earnings Per Share

Basic earnings per share (EPS) is based upon “Net Income Attributable to Chevron Corporation” (“earnings”) and includes the effects of deferrals of salary and other compensation awards that are invested in Chevron stock units by certain officers and employees of the company. Diluted EPS includes the effects of these items as well as the dilutive effects of outstanding stock options awarded under the company’s stock option programs (refer to Note 21, “Stock Options and Other Share-Based Compensation,” beginning on page FS-50). The table below sets forth the computation of basic and diluted EPS:

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

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

Note 12

Operating Segments and Geographic Data

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

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

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

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

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

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

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

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

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

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

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

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

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

	Year ended December 31		
	2014	2013	2012
Upstream			
United States	**$ 2,043**	$ 2,333	$ 2,820
International	**9,217**	12,470	16,554
Total Upstream	**11,260**	14,803	19,374
Downstream			
United States	**1,302**	364	1,051

International		**467**		389	587
Total Downstream		**1,769**		753	1,638
All Other		**(1,137)**		(1,248)	(1,016)
Total Income Tax Expense	**$**	**11,892**	$	14,308 $	19,996

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 13. Information related to properties, plant and equipment by segment is contained in Note 14, on page FS-41.

Note 13

Investments and Advances

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

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

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

Tengizchevroil Chevron has a 50 percent equity ownership interest in Tengizchevroil (TCO), which operates the Tengiz and Korolev crude oil fields in Kazakhstan. At December 31, 2014, the company's carrying value of its investment in TCO was about $150 higher than the amount of underlying equity in TCO's net assets. This difference results from Chevron acquiring a portion of its interest in TCO at a value greater than the underlying book value for that portion of TCO's net assets. See Note 8, on page FS-34, for summarized financial information for 100 percent of TCO.

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

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

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

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

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

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

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

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

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

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

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

Note 14
Properties, Plant and Equipment[1]

	At December 31						Year ended December 31					
	Gross Investment at Cost			Net Investment			Additions at Cost[2]			Depreciation Expense[3]		
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Upstream												
United States	**$ 96,850**	$ 89,555	$ 81,908	**$ 45,864**	$ 41,831	$ 37,909	**$ 9,688**	$ 8,188	$ 8,211	**$ 5,127**	$ 4,412	$ 3,902
International	**192,637**	169,623	145,799	**118,926**	104,100	85,318	**24,920**	27,383	21,343	**9,688**	8,336	8,015
Total Upstream	**289,487**	259,178	227,707	**164,790**	145,931	123,227	**34,608**	35,571	29,554	**14,815**	12,748	11,917
Downstream												
United States	**22,640**	22,407	21,792	**11,019**	11,481	11,333	**588**	1,154	1,498	**886**	780	799
International	**9,334**	9,303	8,990	**4,219**	4,139	3,930	**530**	653	2,544	**396**	360	308

Total Downstream	**31,974**	31,710	30,782	**15,238**	15,620	15,263	**1,118**	1,807	4,042	**1,282**	1,140	1,107
All Other												
United States	**5,673**	5,402	4,959	**3,077**	3,194	2,845	**581**	721	415	**680**	286	384
International	**155**	143	33	**68**	84	13	**25**	23	4	**16**	12	5
Total All Other	**5,828**	5,545	4,992	**3,145**	3,278	2,858	**606**	744	419	**696**	298	389
Total United States	**125,163**	117,364	108,659	**59,960**	56,506	52,087	**10,857**	10,063	10,124	**6,693**	5,478	5,085
Total International	**202,126**	179,069	154,822	**123,213**	108,323	89,261	**25,475**	28,059	23,891	**10,100**	8,708	8,328
Total	**$327,289**	$296,433	$263,481	**$183,173**	$164,829	$141,348	**$ 36,332**	$ 38,122	$ 34,015	**$ 16,793**	$ 14,186	$ 13,413

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

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

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

Note 15

Litigation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Note 16
Taxes

Income Taxes

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

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

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

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

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

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

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

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

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

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

	At December 31	
	2014	2013
Prepaid expenses and other current assets	**$ (1,071)**	$ (1,341)

Deferred charges and other assets	**(3,597)**	(2,954)
Federal and other taxes on income	**813**	583
Noncurrent deferred income taxes	**21,920**	21,301
Total deferred income taxes, net	**$ 18,065**	$ 17,589

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

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

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

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

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

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

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

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

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

Taxes Other Than on Income

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

Note 17

Long-Term Debt

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

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

[1] Interest rate at December 31, 2014.
[2] Weighted-average interest rate at December 31, 2014.

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

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

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

See Note 9, beginning on page FS-34, for information concerning the fair value of the company's long-term debt.

Note 18
Short-Term Debt

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

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

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

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

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

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

Note 19
New Accounting Standards

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

Note 20
Accounting for Suspended Exploratory Wells

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

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

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

* Represents property sales.

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

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

* Certain projects have multiple wells or fields or both.

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

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

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

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

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

Note 21
Stock Options and Other Share-Based Compensation

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

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

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

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

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

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

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

1 Expected term is based on historical exercise and postvesting cancellation data.
2 Volatility rate is based on historical stock prices over an appropriate period, generally equal to the expected term.

A summary of option activity during 2014 is presented below:

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

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

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

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

Notes to the Consolidated Financial Statements
Millions of dollars, except per-share amounts

Note 22
Employee Benefit Plans

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1 U.S. equities include investments in the company's common stock in the amount of $24 at December 31, 2014, and $28 at December 31, 2013.
2 Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly index funds. For these index funds, the Level 2 designation is partially based on the restriction that advance notification of redemptions, typically two business days, is required.
3 Mixed funds are composed of funds that invest in both equity and fixed-income instruments in order to diversify and lower risk.

4 The year-end valuations of the U.S. real estate assets are based on internal appraisals by the real estate managers, which are updates of third-party appraisals that occur at least once a year for each property in the portfolio.
5 The “Other” asset class includes net payables for securities purchased but not yet settled (Level 1); dividends and interest- and tax-related receivables (Level 2); insurance contracts and investments in private-equity limited partnerships (Level 3).

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

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

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

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

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

The company does not prefund its OPEB obligations.

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

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

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

	Pension Benefits		Other
	U.S.	Int’l.	Benefits
2015	$ 1,398	$ 225	$ 198
2016	$ 1,346	$ 315	$ 203
2017	$ 1,347	$ 322	$ 207
2018	$ 1,340	$ 355	$ 212

2019	$	1,319	$	374	$	216
2020-2024	$	5,966	$	2,004	$	1,113

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

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

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

Employee Incentive Plans The Chevron Incentive Plan is an annual cash bonus plan for eligible employees that links awards to corporate, business unit and individual performance in the prior year. Charges to expense for cash bonuses were $965, $871 and $898 in 2014, 2013 and 2012, respectively. Chevron also has the LTIP for officers and other regular salaried employees of the company and its subsidiaries who hold positions of significant responsibility. Awards under the LTIP consist of stock options and other share-based compensation that are described in Note 21, beginning on page FS-50.

Note 23
Other Contingencies and Commitments

Income Taxes The company calculates its income tax expense and liabilities quarterly. These liabilities generally are subject to audit and are not finalized with the individual taxing authorities until several years after the end of the annual period for which income taxes have been calculated. Refer to Note 16, beginning on page FS-45, for a discussion of the periods for which tax returns have been audited for the company's major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return.

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

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

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

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

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements The company and its subsidiaries have certain contingent liabilities with respect to long-term unconditional purchase obligations and commitments, including throughput and take-or-pay agreements, some of which relate to suppliers' financing arrangements. The agreements typically provide goods and services, such as pipeline and storage capacity, drilling rigs, utilities, and petroleum products, to be used or sold in the ordinary course of the company's business. The aggregate approximate amounts of required payments under these various commitments are: 2015 – $3,600; 2016 – $3,000; 2017 – $2,300; 2018 – $2,100; 2019 – $1,600; 2020 and after – $4,500. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $3,700 in 2014, $3,600 in 2013 and $3,600 in 2012.

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

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

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

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

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

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

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

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

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

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

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

Note 24

Asset Retirement Obligations

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

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

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

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

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

Note 25

Other Financial Information

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

Other financial information is as follows:

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

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

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

Five Year Financial Summary

Unaudited

Millions of dollars, except per-share amounts	**2014**	2013	2012	2011	2010
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues*	**$ 200,494**	$ 220,156	$ 230,590	$ 244,371	$ 198,198
Income from equity affiliates and other income	**11,476**	8,692	11,319	9,335	6,730
Total Revenues and Other Income	**211,970**	228,848	241,909	253,706	204,928
Total Costs and Other Deductions	**180,768**	192,943	195,577	206,072	172,873
Income Before Income Tax Expense	**31,202**	35,905	46,332	47,634	32,055
Income Tax Expense	**11,892**	14,308	19,996	20,626	12,919
Net Income	**19,310**	21,597	26,336	27,008	19,136
Less: Net income attributable to noncontrolling interests	**69**	174	157	113	112
Net Income Attributable to Chevron Corporation	**$ 19,241**	$ 21,423	$ 26,179	$ 26,895	$ 19,024
Per Share of Common Stock					
Net Income Attributable to Chevron					
– Basic	**$ 10.21**	$ 11.18	$ 13.42	$ 13.54	$ 9.53
– Diluted	**$ 10.14**	$ 11.09	$ 13.32	$ 13.44	$ 9.48
Cash Dividends Per Share	**$ 4.21**	$ 3.90	$ 3.51	$ 3.09	$ 2.84
Balance Sheet Data (at December 31)					
Current assets	**$ 42,232**	$ 50,250	$ 55,720	$ 53,234	$ 48,841
Noncurrent assets	**223,794**	203,503	177,262	156,240	135,928
Total Assets	**266,026**	253,753	232,982	209,474	184,769
Short-term debt	**3,790**	374	127	340	187
Other current liabilities	**28,136**	32,644	34,085	33,260	28,825
Long-term debt and capital lease obligations	**24,028**	20,057	12,065	9,812	11,289
Other noncurrent liabilities	**53,881**	50,251	48,873	43,881	38,657
Total Liabilities	**109,835**	103,326	95,150	87,293	78,958
Total Chevron Corporation Stockholders' Equity	**$ 155,028**	$ 149,113	$ 136,524	$ 121,382	$ 105,081
Noncontrolling interests	**1,163**	1,314	1,308	799	730
Total Equity	**$ 156,191**	$ 150,427	$ 137,832	$ 122,181	$ 105,811
* Includes excise, value-added and similar taxes:	**$ 8,186**	$ 8,492	$ 8,010	$ 8,085	$ 8,591

Supplemental Information on Oil and Gas Producing Activities - Unaudited

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

Table I - Costs Incurred in Exploration, Property Acquisitions and Development[1]

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

[1] Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 24, "Asset Retirement Obligations," on page FS-59.

2 Does not include properties acquired in nonmonetary transactions.

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

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

	2014	2013	2012	
Total cost incurred	$ 33.7	$ 33.5	$ 26.1	
Non-oil and gas activities	4.6	5.8	5.0	(Primarily includes LNG, gas-to-liquids and transportation activities)
ARO	(1.2)	(1.4)	(0.7)	
Upstream C&E	$ 37.1	$ 37.9	$ 30.4	Reference Page FS-13 Upstream total

reserves and changes in estimated discounted future net cash flows. The amounts for consolidated companies are organized by geographic areas including the United States, Other Americas, Africa, Asia, Australia/Oceania and Europe. Amounts for affiliated companies include Chevron's equity interests in Tengizchevroil (TCO) in the Republic of Kazakhstan and in other affiliates, principally in Venezuela and Angola. Refer to Note 13, beginning on page FS-40, for a discussion of the company's major equity affiliates.

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

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

Support equipment depreciation	589	178	613	1,101	305	137	2,923	480	—
Accumulated provisions	43,934	6,100	16,380	25,786	2,139	8,420	102,759	2,795	551
Net Capitalized Costs	$ 37,612	$ 10,294	$ 19,256	$ 22,145	$ 14,845	$ 2,781	$ 106,933	$ 6,141	$ 2,923

Table III - Results of Operations for Oil and Gas Producing Activities[1]

The company's results of operations from oil and gas producing activities for the years 2014, 2013 and 2012 are shown in the following table. Net income from exploration and production activities as reported on page FS-38 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 FS-38.

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

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

2 Represents accretion of ARO liability. Refer to Note 24, “Asset Retirement Obligations,” on page FS-59.
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 Activities[1], continued

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

1 The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
2 Represents accretion of ARO liability. Refer to Note 24, “Asset Retirement Obligations,” on page FS-59.
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 Costs[1]

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

1 The value of owned production consumed in operations as fuel has been eliminated from revenues and production expenses, and the related volumes have been deducted from net production in calculating the unit average sales price and production cost. This has no effect on the results of producing operations.
2 Natural gas converted to oil-equivalent gas (OEG) barrels at a rate of 6 MCF = 1 OEG barrel.

Supplemental Information on Oil and Gas Producing Activities - Unaudited

Table V Reserve Quantity Information

Summary of Net Oil and Gas Reserves

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

At December 31, 2014, proved reserves for the company were 11.1 billion BOE. The company's estimated net proved reserves of liquids including crude oil, condensate, natural gas liquids and synthetic oil for the years 2012, 2013 and 2014 are shown in the table on page FS-68. The company's estimated net proved reserves of natural gas are shown on page FS-69.

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

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

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

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

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

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

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

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

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

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

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

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

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

	Consolidated Companies								Affiliated Companies			Total Consolidated
		Other			Australia/		Synthetic			Synthetic		and Affiliated
Millions of barrels	U.S.	Americas[1]	Africa	Asia	Oceania	Europe	Oil[2]	Total	TCO	Oil	Other[3]	Companies
Reserves at January 1, 2012	1,311	113	1,155	894	140	159	523	4,295	1,759	244	157	6,455
Changes attributable to:												
Revisions	104	20	66	97	4	16	6	313	59	(6)	24	390
Improved recovery	24	8	30	6	—	9	—	77	—	—	—	77
Extensions and discoveries	77	101	30	2	7	—	—	217	—	—	1	218
Purchases	10	—	—	—	—	—	—	10	—	—	—	10
Sales	(1)	—	—	(15)	(7)	—	—	(23)	—	—	—	(23)
Production	(166)	(19)	(151)	(147)	(10)	(27)	(16)	(536)	(86)	(6)	(18)	(646)
Reserves at December 31, 2012[4]	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, 2013[4]	1,330	243	1,104	792	131	166	537	4,303	1,668	220	154	6,345
Changes attributable to:												
Revisions	**90**	**—**	**74**	**80**	**19**	**9**	**(32)**	**240**	**41**	**(4)**	**—**	**277**
Improved recovery	**19**	**1**	**1**	**8**	**—**	**5**	**—**	**34**	**—**	**—**	**—**	**34**
Extensions and discoveries	**164**	**18**	**2**	**7**	**—**	**8**	**19**	**218**	**—**	**—**	**1**	**219**
Purchases	**1**	**—**	**—**	**—**	**—**	**—**	**26**	**27**	**—**	**—**	**—**	**27**
Sales	**(6)**	**—**	**(20)**	**—**	**—**	**(3)**	**—**	**(29)**	**—**	**—**	**—**	**(29)**
Production	**(166)**	**(24)**	**(140)**	**(135)**	**(8)**	**(19)**	**(16)**	**(508)**	**(94)**	**(12)**	**(10)**	**(624)**
Reserves at December 31, 2014[4]	**1,432**	**238**	**1,021**	**752**	**142**	**166**	**534**	**4,285**	**1,615**	**204**	**145**	**6,249**

1 Ending reserve balances in North America were 142, 141 and 121 and in South America were 96, 102 and 102 in 2014, 2013 and 2012, respectively.
2 Reserves associated with Canada.
3 Ending reserve balances in Africa were 37, 37 and 41 and in South America were 108, 117 and 123 in 2014, 2013 and 2012, respectively.
4 Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-11 for the definition of a PSC). PSC-related reserve quantities are 19 percent, 20 percent and 20 percent for consolidated companies for 2014, 2013 and 2012, respectively.

Net Proved Reserves of Natural Gas

	Consolidated Companies							Affiliated Companies		Total Consolidated
		Other			Australia/					and Affiliated
Billions of cubic feet (BCF)	U.S.	Americas[1]	Africa	Asia	Oceania	Europe	Total	TCO	Other[2]	Companies
Reserves at January 1, 2012	3,646	1,664	3,196	6,721	9,744	258	25,229	2,251	1,203	28,683
Changes attributable to:										

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

1 Ending reserve balances in North America and South America were 59, 54, 49 and 1,064, 1,246, 1,426 in 2014, 2013 and 2012, respectively.
2 Ending reserve balances in Africa and South America were 1,043, 1,009, 1,068 and 189, 177, 174 in 2014, 2013 and 2012, respectively.
3 Total "as sold" volumes are 1,695 BCF, 1,702 BCF and 1,666 BCF for 2014, 2013 and 2012, respectively; 2013 conformed to 2014 presentation.
4 Includes reserve quantities related to production-sharing contracts (PSC) (refer to page E-11 for the definition of a PSC). PSC-related reserve quantities are 19 percent, 20 percent and 21 percent for consolidated companies for 2014, 2013 and 2012, respectively.

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

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

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

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

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

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

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

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

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

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

	Consolidated Companies							Affiliated Companies		Total Consolidated and Affiliated Companies
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other	
At December 31, 2014										
Future cash inflows from production	**$138,385**	**$ 67,102**	**$103,304**	**$ 99,741**	**$142,541**	**$ 18,168**	**$569,241**	**$144,721**	**$ 37,511**	**$ 751,473**
Future production costs	**(42,817)**	**(30,899)**	**(26,992)**	**(34,359)**	**(12,744)**	**(10,814)**	**(158,625)**	**(30,015)**	**(17,061)**	**(205,701)**
Future development costs	**(13,616)**	**(8,283)**	**(9,486)**	**(12,629)**	**(15,681)**	**(3,031)**	**(62,726)**	**(19,349)**	**(4,454)**	**(86,529)**
Future income taxes	**(27,129)**	**(8,445)**	**(47,884)**	**(24,225)**	**(34,235)**	**(2,692)**	**(144,610)**	**(28,607)**	**(6,634)**	**(179,851)**
Undiscounted future net cash flows	**54,823**	**19,475**	**18,942**	**28,528**	**79,881**	**1,631**	**203,280**	**66,750**	**9,362**	**279,392**
10 percent midyear annual discount for timing of estimated cash flows	**(23,257)**	**(12,082)**	**(6,145)**	**(8,570)**	**(43,325)**	**(380)**	**(93,759)**	**(34,987)**	**(5,294)**	**(134,040)**
Standardized Measure Net Cash Flows	**$ 31,566**	**$ 7,393**	**$ 12,797**	**$ 19,958**	**$ 36,556**	**$ 1,251**	**$109,521**	**$ 31,763**	**$ 4,068**	**$ 145,352**

	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other	Total Consolidated and Affiliated Companies
At December 31, 2013[1]										
Future cash inflows from production	$136,942	$ 73,468	$117,119	$111,970	$130,620	$ 20,232	$590,351	$157,108	$ 43,380	$ 790,839
Future production costs	(39,009)	(29,373)	(27,800)	(35,716)	(12,593)	(10,099)	(154,590)	(32,245)	(18,027)	(204,862)
Future development costs	(12,058)	(10,149)	(10,983)	(17,290)	(18,220)	(2,644)	(71,344)	(12,852)	(3,879)	(88,075)
Future income taxes	(28,458)	(9,454)	(53,953)	(26,162)	(29,942)	(4,727)	(152,696)	(33,603)	(9,418)	(195,717)
Undiscounted future net cash flows	57,417	24,492	24,383	32,802	69,865	2,762	211,721	78,408	12,056	302,185
10 percent midyear annual discount for timing of estimated cash flows	(23,055)	(15,217)	(8,165)	(10,901)	(39,117)	(888)	(97,343)	(41,444)	(6,482)	(145,269)
Standardized Measure Net Cash Flows	$ 34,362	$ 9,275	$ 16,218	$ 21,901	$ 30,748	$ 1,874	$114,378	$ 36,964	$ 5,574	$ 156,916

	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other	Total Consolidated and Affiliated Companies
At December 31, 2012[1]										
Future cash inflows from production	$139,856	$ 72,548	$122,189	$121,849	$134,009	$ 19,653	$610,104	$169,966	$ 47,496	$ 827,566
Future production costs	(41,773)	(27,191)	(24,592)	(35,713)	(15,649)	(8,768)	(153,686)	(32,085)	(19,899)	(205,670)
Future development costs	(11,192)	(14,810)	(14,601)	(17,275)	(24,923)	(1,946)	(84,747)	(12,355)	(3,710)	(100,812)
Future income taxes	(32,357)	(9,902)	(48,683)	(30,763)	(28,031)	(5,589)	(155,325)	(37,658)	(13,363)	(206,346)
Undiscounted future net cash flows	54,534	20,645	34,313	38,098	65,406	3,350	216,346	87,868	10,524	314,738
10 percent midyear annual discount for timing of estimated cash flows	(23,055)	(14,331)	(12,429)	(13,033)	(42,012)	(860)	(105,720)	(47,534)	(5,644)	(158,898)
Standardized Measure Net Cash Flows	$ 31,479	$ 6,314	$ 21,884	$ 25,065	$ 23,394	$ 2,490	$110,626	$ 40,334	$ 4,880	$ 155,840

[1] 2012 and 2013 conformed to 2014 presentation.

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

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

Millions of dollars	Consolidated Companies[1]	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2012	$ 106,948	$ 45,891	$ 152,839
Sales and transfers of oil and gas produced net of production costs	(49,094)	(7,708)	(56,802)
Development costs incurred	18,013	942	18,955
Purchases of reserves	376	—	376
Sales of reserves	(1,665)	—	(1,665)
Extensions, discoveries and improved recovery less related costs	9,296	106	9,402
Revisions of previous quantity estimates	26,060	3,759	29,819
Net changes in prices, development and production costs	(18,752)	(2,266)	(21,018)
Accretion of discount	18,026	6,322	24,348
Net change in income tax	1,418	(1,832)	(414)
Net change for 2012	3,678	(677)	3,001

Present Value at December 31, 2012	$ 110,626	$ 45,214	$ 155,840
Sales and transfers of oil and gas produced net of production costs	(43,760)	(8,692)	(52,452)
Development costs incurred	22,907	1,411	24,318
Purchases of reserves	184	—	184
Sales of reserves	243	—	243
Extensions, discoveries and improved recovery less related costs	3,135	—	3,135
Revisions of previous quantity estimates	22,796	1,306	24,102
Net changes in prices, development and production costs	(22,591)	(5,925)	(28,516)
Accretion of discount	18,510	6,406	24,916
Net change in income tax	2,328	2,818	5,146
Net change for 2013	3,752	(2,676)	1,076
Present Value at December 31, 2013	$ 114,378	$ 42,538	$ 156,916
Sales and transfers of oil and gas produced net of production costs	**(38,935)**	**(7,578)**	**(46,513)**
Development costs incurred	**25,687**	**1,963**	**27,650**
Purchases of reserves	**255**	**—**	**255**
Sales of reserves	**(1,178)**	**—**	**(1,178)**
Extensions, discoveries and improved recovery less related costs	**3,956**	**215**	**4,171**
Revisions of previous quantity estimates	**17,462**	**1,573**	**19,035**
Net changes in prices, development and production costs	**(34,953)**	**(12,496)**	**(47,449)**
Accretion of discount	**18,884**	**5,926**	**24,810**
Net change in income tax	**3,965**	**3,690**	**7,655**
Net change for 2014	**(4,857)**	**(6,707)**	**(11,564)**
Present Value at December 31, 2014	**$ 109,521**	**$ 35,831**	**$ 145,352**

[1] 2012 and 2013 conformed to 2014 presentation.

EXHIBIT INDEX

Exhibit No.	Description
3.1	Restated Certificate of Incorporation of Chevron Corporation, dated May 30, 2008, filed as Exhibit 3.1 to Chevron Corporation's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2008, and incorporated herein by reference.
3.2	By-Laws of Chevron Corporation, as amended December 10, 2014, filed as Exhibit 3.1 to Chevron Corporation's Current Report on Form 8-K filed December 12, 2014, and incorporated herein by reference.
4.1	Pursuant to the Instructions to Exhibits, certain instruments defining the rights of holders of long-term debt securities of the company and its consolidated subsidiaries are not filed because the total amount of securities authorized under any such instrument does not exceed 10 percent of the total assets of the corporation and its subsidiaries on a consolidated basis. A copy of such instrument will be furnished to the Securities and Exchange Commission upon request.
4.2	Confidential Stockholder Voting Policy of Chevron Corporation, filed as Exhibit 4.2 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.1	Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan, filed as Exhibit 10.1 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.2	Form of Retainer Stock Option Agreement under the Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan, filed as Exhibit 10.17 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference.
10.3	Form of Stock Units Agreement under the Chevron Corporation Non-Employee Directors' Equity Compensation and Deferral Plan, filed as Exhibit 10.19 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.

10.4	Chevron Incentive Plan, filed as Exhibit 10.2 to Chevron Corporation’s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.5*	Summary of Chevron Incentive Plan Award Criteria.
10.6	Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit B to Chevron Corporation’s Notice of the 2013 Annual Meeting and 2013 Proxy Statement filed April 11, 2013, and incorporated herein by reference.
10.7*	Form of Restricted Stock Units Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation.
10.8*	Form of Non-Qualified Stock Options Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation.
10.9*	Form of Performance Shares Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation.
10.10*	Form of Stock Appreciation Rights Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation.
10.11	Chevron Corporation Deferred Compensation Plan for Management Employees, filed as Exhibit 10.5 to Chevron Corporation’s Current Report on Form 8-K filed December 13, 2005, and incorporated herein by reference.
10.12	Chevron Corporation Deferred Compensation Plan for Management Employees II, filed as Exhibit 10.5 to Chevron Corporation’s Annual Report on Form 10-K filed December 31, 2008, and incorporated herein by reference.
10.13	Chevron Corporation Retirement Restoration Plan, filed as Exhibit 10.6 to Chevron Corporation’s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.14	Chevron Corporation ESIP Restoration Plan, filed as Exhibit 10.7 to Chevron Corporation’s Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.15	Agreement between Chevron Corporation and R. Hewitt Pate, filed as Exhibit 10.16 to Chevron's Annual Report on Form 10-K for the year ended December 31, 2011, and incorporated herein by reference.
12.1*	Computation of Ratio of Earnings to Fixed Charges (page E-3).
21.1*	Subsidiaries of Chevron Corporation (page E-4).

Exhibit No.	Description
23.1*	Consent of PricewaterhouseCoopers LLP (page E-5).
24.1 to 24.12*	Powers of Attorney for certain directors of Chevron Corporation, authorizing the signing of the Annual Report on Form 10-K on their behalf.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of the company’s Chief Executive Officer (page E-6).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of the company’s Chief Financial Officer (page E-7).
32.1*	Section 1350 Certification of the company’s Chief Executive Officer (page E-8).
32.2*	Section 1350 Certification of the company’s Chief Financial Officer (page E-9).
95*	Mine Safety Disclosure.
99.1*	Definitions of Selected Energy and Financial Terms (pages E-10 through E-11).
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.LAB*	XBRL Label Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.

Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is “unaudited” or “unreviewed.”

* Filed herewith.

Copies of the above exhibits not contained herein are available to any security holder upon written request to the Corporate Governance Department, Chevron Corporation, 6001 Bollinger Canyon Road, San Ramon, California 94583-2324.