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, 2016
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 — $197,763,938,564 (As of June 30, 2016)

Number of Shares of Common Stock outstanding as of February 15, 2017 — 1,893,102,970

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2017 Annual Meeting and 2017 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company's 2017 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 or phrases such as "anticipates," "expects," "intends," "plans," "targets," "forecasts," "projects," "believes," "seeks," "schedules," "estimates," "positions," "pursues," "may," "could," "should," "budgets," "outlook," "focus," "on schedule," "on track," "goals," "objectives," "strategies" 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; the company's ability to realize anticipated cost savings and expenditure reductions; 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 the company's suppliers, vendors, partners and equity affiliates, particularly during extended periods of low prices for crude oil and natural gas; 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 operations due to war, accidents, political events, civil unrest, severe weather, cyber threats and terrorist acts, crude oil production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries, or other natural or human causes beyond its control; changing economic, regulatory and political environments in the various countries in which the company operates; general domestic and international economic and political conditions; the potential liability for remedial actions or assessments under existing or future environmental regulations and litigation; significant operational, investment or product changes required by existing or future environmental statutes and regulations, including international agreements and national or regional legislation and regulatory measures to limit or reduce greenhouse gas emissions; the potential liability resulting from other pending or future litigation; the company's future acquisition or disposition of assets or the delay or failure of such transactions to close based on required closing conditions set forth in the applicable transaction agreements; the potential for 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; material reductions in corporate liquidity and access to debt markets; the effects of changed accounting rules under generally accepted accounting principles promulgated by rule-setting bodies; the company's ability to identify and mitigate the risks and hazards inherent in operating in the global energy industry; and the factors set forth under the heading "Risk Factors" on pages 20 through 22 in this report. 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 integrated energy and chemicals operations. 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-5. As of December 31, 2016, Chevron had approximately 55,200 employees (including about 3,200 service station employees). Approximately 26,500 employees (including about 3,100 service station employees), or 48 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, as well as 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 deliver industry-leading results and superior shareholder value in any business environment. In the upstream, the company's strategy is to deliver industry-leading returns while developing high-value resource opportunities. In the downstream, the company's strategy is to grow earnings across the value chain and make targeted investments to lead the industry in returns.

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.

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* 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, 2016, and assets as of the end of 2016 and 2015 — for the United States and the company's international geographic areas — are in Note 15 to the Consolidated Financial Statements beginning on page FS-40. Similar comparative data for the company's investments in and income from equity affiliates and property, plant and equipment are in Notes 16 and 17 on pages FS-43 through FS-44. Refer to page FS-14 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-69 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 2014 and each year-end from 2014 through 2016. 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, 2016, 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, 2016, 23 percent of the company's net proved oil-equivalent reserves were located in Kazakhstan, 20 percent were located in Australia and 18 percent were located in the United States.

The net proved reserve balances at the end of each of the three years 2014 through 2016 are shown in the following table:

		At December 31	
	2016	2015	2014
Liquids — Millions of barrels			
Consolidated Companies	**4,131**	4,262	4,285
Affiliated Companies	**2,197**	2,000	1,964
Total Liquids	**6,328**	6,262	6,249
Natural Gas — Billions of cubic feet			
Consolidated Companies	**25,432**	25,946	25,707
Affiliated Companies	**3,328**	3,491	3,409
Total Natural Gas	**28,760**	29,437	29,116
Oil-Equivalent — Millions of barrels*			
Consolidated Companies	**8,370**	8,586	8,570
Affiliated Companies	**2,752**	2,582	2,532
Total Oil-Equivalent	**11,122**	11,168	11,102

* Oil-equivalent conversion ratio is 6,000 cubic feet of natural gas = 1 barrel of crude 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 2016 and 2015 by the company and its affiliates. Worldwide oil-equivalent production of 2.594 million barrels per day in 2016 was down 1 percent from 2015. Production increases from major capital projects, shale and tight properties, and base business were more than offset by normal field declines, the impact of asset sales, the Partitioned Zone shut-in, the effects of civil unrest in Nigeria and planned turnaround activity. Refer to the "Results of Operations" section beginning on page FS-6 for a detailed discussion of the factors explaining the 2014 through 2016 changes in production for crude oil and natural gas liquids, and natural gas, and refer to Table V on pages FS-69 and FS-72 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)	**2016**	2015	**2016**	2015	**2016**	2015
United States	**691**	720	**504**	501	**1,120**	1,310
Other Americas						
Argentina	**26**	27	**20**	21	**32**	36
Brazil	**16**	18	**16**	17	**5**	5
Canada[2]	**92**	69	**83**	67	**55**	14
Colombia	**21**	27	**—**	—	**127**	161
Trinidad and Tobago	**12**	19	**—**	—	**74**	116
Total Other Americas	**167**	160	**119**	105	**293**	332
Africa						
Angola	**114**	119	**106**	110	**52**	52
Democratic Republic of the Congo	**2**	3	**2**	2	**1**	1
Nigeria	**235**	270	**208**	230	**159**	246
Republic of Congo	**25**	20	**23**	18	**11**	11
Total Africa	**376**	412	**339**	360	**223**	310
Asia						
Azerbaijan	**32**	34	**30**	32	**13**	12
Bangladesh	**114**	123	**4**	3	**658**	720
China	**27**	24	**18**	24	**51**	—
Indonesia	**203**	207	**173**	176	**182**	185
Kazakhstan	**62**	56	**37**	34	**154**	138
Myanmar	**21**	20	**—**	—	**128**	117
Partitioned Zone[3]	**—**	28	**—**	27	**—**	5
Philippines	**26**	23	**3**	3	**138**	122
Thailand	**245**	238	**71**	66	**1,051**	1,033
Total Asia	**730**	753	**336**	365	**2,375**	2,332
Australia/Oceania						
Australia	**124**	94	**21**	21	**615**	439
Total Australia/Oceania	**124**	94	**21**	21	**615**	439
Europe						
Denmark	**22**	24	**14**	16	**48**	50
United Kingdom	**64**	59	**43**	40	**122**	115
Total Europe	**86**	83	**57**	56	**170**	165
Total Consolidated Companies	**2,174**	2,222	**1,376**	1,408	**4,796**	4,888
Affiliates[2,4]	**420**	400	**343**	336	**456**	381
Total Including Affiliates[5]	**2,594**	2,622	**1,719**	1,744	**5,252**	5,269

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

[2] Includes synthetic oil: Canada, net	**50**	47	**50**	47	**—**	—

Venezuelan affiliate, net	**28**	29	**28**	29	**—**	—

[3] Located between Saudi Arabia and Kuwait.

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

[5] Volumes include natural gas consumed in operations of 486 million and 496 million cubic feet per day in 2016 and 2015, respectively. Total "as sold" natural gas volumes were 4,766 million and 4,773 million cubic feet per day for 2016 and 2015, respectively.

Production Outlook

The company estimates its average worldwide oil-equivalent production in 2017 will grow 4 to 9 percent compared to 2016, assuming a Brent crude oil price of $50 per barrel and before asset sales. 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-68 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 2016, 2015 and 2014.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2016 for the company and its affiliates:

				At December 31, 2016
	Productive Oil Wells*		**Productive Gas Wells ***	
	Gross	**Net**	**Gross**	**Net**
United States	45,659	31,679	8,492	3,633
Other Americas	1,202	767	99	54
Africa	1,824	692	17	7
Asia	15,118	12,937	4,029	2,352
Australia/Oceania	568	317	77	15
Europe	319	68	177	38
Total Consolidated Companies	64,690	46,460	12,891	6,099
Affiliates	1,468	508	7	2
Total Including Affiliates	66,158	46,968	12,898	6,101
Multiple completion wells included above	889	608	225	184

* Gross wells represent the total number of wells in which Chevron has an ownership interest. Net wells represent the sum of Chevron's ownership interest in gross wells.

Acreage

At December 31, 2016, 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[2]		**Developed**		**Developed and Undeveloped**	
Thousands of acres[1]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States	4,491	3,578	5,307	3,543	9,798	7,121
Other Americas	27,154	14,916	1,376	368	28,530	15,284
Africa	9,340	3,880	2,326	946	11,666	4,826
Asia	27,890	13,328	1,719	956	29,609	14,284
Australia/Oceania	21,325	14,660	2,002	803	23,327	15,463
Europe	2,121	1,023	407	52	2,528	1,075
Total Consolidated Companies	92,321	51,385	13,137	6,668	105,458	58,053
Affiliates	516	225	280	108	796	333
Total Including Affiliates	92,837	51,610	13,417	6,776	106,254	58,386

[1] Gross acres represent the total number of acres in which Chevron has an ownership interest. Net acres represent the sum of Chevron's ownership interest in gross acres.

[2] The gross undeveloped acres that will expire in 2017, 2018 and 2019 if production is not established by certain required dates are 2,549, 4,256 and 2,058, 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 140 billion cubic feet of natural gas to third parties from 2017 through 2019. 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 are all based on contracts with indexed pricing terms.

Outside the United States, the company is contractually committed to deliver a total of 1,913 billion cubic feet of natural gas to third parties from 2017 through 2019 from operations in Australia, Colombia, Denmark, Indonesia 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-65 for details associated with the company's development expenditures and costs of proved property acquisitions for 2016, 2015 and 2014.

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, 2016. 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 12/31/16		Net Wells Completed 2016		2015		2014	
	Gross	**Net**	**Prod.**	**Dry**	**Prod.**	**Dry**	**Prod.**	**Dry**
United States	**70**	**47**	**420**	**4**	873	3	1,085	8
Other Americas	**39**	**21**	**45**	**—**	99	—	81	—
Africa	**13**	**4**	**17**	**—**	9	—	9	—
Asia	**50**	**29**	**470**	**6**	828	5	1,025	4
Australia/Oceania	**—**	**—**	**4**	**—**	4	—	9	—
Europe	**3**	**—**	**3**	**—**	2	—	2	—
Total Consolidated Companies	**175**	**101**	**959**	**10**	1,815	8	2,211	12
Affiliates	**43**	**18**	**38**	**—**	26	—	25	1
Total Including Affiliates	**218**	**119**	**997**	**10**	1,841	8	2,236	13

* Gross wells represent the total number of wells in which Chevron has an ownership interest. Net wells represent the sum of Chevron's ownership interest in gross wells.

Exploration Activities

Refer to Table I on page FS-65 for detail on the company's exploration expenditures and costs of unproved property acquisitions for 2016, 2015 and 2014.

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, 2016. "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 12/31/16		Net Wells Completed 2016		2015		2014	
	Gross	**Net**	**Prod.**	**Dry**	**Prod.**	**Dry**	**Prod.**	**Dry**
United States	**3**	**3**	**4**	**1**	16	4	20	12
Other Americas	**—**	**—**	**4**	**—**	5	1	3	—
Africa	**—**	**—**	**1**	**1**	3	—	1	2
Asia	**—**	**—**	**3**	**—**	5	1	7	2
Australia/Oceania	**—**	**—**	**—**	**—**	1	4	3	—
Europe	**—**	**—**	**—**	**—**	3	—	3	—
Total Consolidated Companies	**3**	**3**	**12**	**2**	33	10	37	16
Affiliates	**—**	**—**	**—**	**—**	—	—	—	—
Total Including Affiliates	**3**	**3**	**12**	**2**	33	10	37	16

* Gross wells represent the total number of wells in which Chevron has an ownership interest. Net wells represent the sum of Chevron's ownership interest in gross wells.

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 2016 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-6, 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-11.

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 the midcontinent region, the Gulf of Mexico, California and the Appalachian Basin. Net oil-equivalent production in the United States during 2016 averaged 691,000 barrels per day.

The company's activities in the midcontinent region are primarily in Colorado, New Mexico, Oklahoma and Texas. During 2016, net daily production in these areas averaged 123,000 barrels of crude oil, 576 million cubic feet of natural gas and 40,000 barrels of natural gas liquids (NGLs). In 2016, the company divested properties in areas including Oklahoma, Texas and Wyoming. The company is pursuing selected opportunities for divestment of additional properties in 2017.

In the Permian Basin of West Texas and southeast New Mexico, the company holds approximately 500,000 and 1,000,000 net acres of shale and tight resources in the Midland and Delaware basins, respectively. This acreage includes multiple stacked formations that enable production from several layers of rock in different geologic zones. The stacked plays multiply the basin’s resource and economic potential by allowing for multiple horizontal wells to be developed from a single pad location using shared facilities and infrastructure, which reduces development costs and improves capital efficiency. Chevron has implemented a factory development strategy in the basin, which utilizes multiwell pads to drill multiple horizontal wells that are completed concurrently using multistage hydraulic fracture stimulation. The company drilled 93 wells and participated in 108 nonoperated wells in the Midland and Delaware basins in 2016.

During 2016, net daily production in the Gulf of Mexico averaged 158,000 barrels of crude oil, 183 million cubic feet of natural gas and 13,000 barrels of NGLs. The company divested selected shelf properties in 2016 and is pursuing divestment of additional shelf assets in 2017. Chevron is also engaged in various exploration, development and production activities in the deepwater Gulf of Mexico.

The deepwater 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. The company has a 40.6 percent interest in the production host facility, which is designed to accommodate production from the Jack/St. Malo development and third-party tiebacks. Total daily production from the Jack and St. Malo fields in 2016 averaged 94,000 barrels of liquids (47,000 net) and 14 million cubic feet of natural gas (7 million net). Production ramp-up and development drilling for the first development phase continued in 2016. In addition, work continued on Stage 2, the second phase of the development plan, which includes four additional development wells, two each at the Jack and St. Malo fields. Start-up of the first Stage 2 development well was achieved in third quarter 2016. Development drilling is planned to continue in 2017. 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 128,000 barrels of crude oil and 33 million cubic feet of natural gas. The Jack and St. Malo fields have an estimated remaining production life of 30 years.

At the 58 percent-owned and operated deepwater Tahiti Field, net daily production averaged 31,000 barrels of crude oil, 13 million cubic feet of natural gas, and 2,000 barrels of NGLs. Four infill production wells were completed in 2016. The next development phase, the Tahiti Vertical Expansion Project, achieved a final investment decision in mid-2016. The expansion project includes four new wells and associated subsea infrastructure. The four wells have been drilled and cased, and completion operations are underway. First oil is expected in 2018. Proved reserves have been recognized for this project. The Tahiti Field has an estimated remaining production life of at least 20 years.

The company has a 15.6 percent nonoperated working interest in the deepwater Mad Dog Field. In 2016, net daily production averaged 8,000 barrels of liquids and 1 million cubic feet of natural gas. The next development phase, the Mad Dog 2 Project, is planned to develop the southern portion of the Mad Dog Field. The development plan includes a new floating production platform with a design capacity of 140,000 barrels of crude oil per day. A final investment decision was reached in February 2017. First oil is expected in 2021. At the end of 2016, proved reserves had not been recognized for the Mad Dog 2 Project.

The development plan for the 60 percent-owned and operated deepwater Big Foot Project includes a 15-slot drilling and production tension leg platform with water injection facilities and a design capacity of 75,000 barrels of crude oil and 25 million cubic feet of natural gas per day. Fabrication of replacement mooring tendons began in mid-2016. Platform installation is expected to resume in late 2017, with first oil expected in late 2018. The field has an estimated production life of 35 years from the time of start-up. Proved reserves have been recognized for this project.

Chevron holds a 25 percent nonoperated working interest in the Stampede Project, the unitized development of the deepwater Knotty Head and Pony discoveries. The planned facilities have a design capacity of 80,000 barrels of crude oil and 40 million cubic feet of natural gas per day. Fabrication and development drilling activities progressed in 2016, with first oil expected in 2018. The field has an estimated production life of 30 years from the time of start-up. Proved reserves have been recognized for this project.

During 2016 and early 2017, the company participated in five appraisal wells and four exploration wells in the deepwater Gulf of Mexico. Drilling was completed on an appraisal well at the Sicily discovery in first quarter 2016. No further operations are planned, and the leases expired in 2016. Drilling was completed on two successful appraisal wells at the Anchor discovery, one in second quarter 2016 and one in early 2017.

Chevron is the operator of an exploration and appraisal program and potential development named Tigris, covering a number of jointly held offshore leases in the northwest portion of Keathley Canyon. This area may have the potential to support a cost-effective, deepwater hub development of multiple fields to a new central host. In 2016, two successful appraisal wells were drilled at the 41 percent-owned Tiber and the 50 percent-owned Guadalupe discoveries. The planned appraisal programs have been completed for the Tiber and Guadalupe discoveries and Chevron filed for Suspension of Production (SOP) on both the Tiber and Guadalupe units. The SOPs are intended to hold the associated leases as the planned development concept matures.

Chevron added ten leases to its deepwater portfolio as a result of awards from the central Gulf of Mexico Lease Sale 241, held in first quarter 2016.

In California, the company has significant production in the San Joaquin Valley. In 2016, net daily production averaged 159,000 barrels of crude oil, 54 million cubic feet of natural gas and 3,000 barrels of NGLs.

The company holds approximately 472,000 net acres in the Marcellus Shale and 309,000 net acres in the Utica Shale, primarily located in southwestern Pennsylvania, eastern Ohio and the West Virginia panhandle. During 2016, net daily production in these areas averaged 290 million cubic feet of natural gas, 5,000 barrels of NGLs and 3,000 barrels of condensate. In April 2016, the company divested its interest in the Antrim Shale in Michigan.

Other Americas

"Other Americas" includes Argentina, Brazil, Canada, Colombia, Greenland, Mexico, Suriname, Trinidad and Tobago and Venezuela. Net oil-equivalent production from these countries averaged 226,000 barrels per day during 2016.

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. Net oil-equivalent production during 2016 averaged 92,000 barrels per day, composed of 33,000 barrels of crude oil, 55 million cubic feet of natural gas and 50,000 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 23.8 percent nonoperated working interest in the unitized Hibernia Southern Extension (HSE) areas offshore Atlantic Canada. Infill drilling continued in 2016.

The company holds a 29.6 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. The mating of the integrated topside with the gravity-based structure was completed in 2016. The platform is scheduled to be towed to the field in first-half 2017, and first oil is expected in late 2017. The project has an expected economic life of 30 years from the time of start-up. Proved reserves have been recognized for this project.

In the Flemish Pass Basin offshore Newfoundland, Chevron holds a 40 percent nonoperated working interest in two exploration blocks, EL1125 and EL1126. A 3-D seismic survey has been completed on these blocks. In addition, the company holds a 35 percent-owned and operated interest in Flemish Pass Basin Block EL1138.

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. Carbon dioxide emissions from the upgrade process are reduced by the colocated Quest carbon capture and storage facilities.

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. Drilling continued during 2016 on an appraisal and land retention program. A total of 53 wells have been tied into production facilities by early 2017.

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 300,000 net acres in the Horn River and Liard shale gas basins in British Columbia. The horizontal appraisal drilling program progressed during 2016. 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 2016, proved reserves had not been recognized for this project.

In April 2016, the company sold its 93.8 percent operated interest in the Aitken Creek and a 42.9 percent nonoperated interest in the Alberta Hub natural gas storage facilities.

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. Additional 2-D seismic data was acquired in 2016 and evaluation of the acreage is ongoing.

Mexico In December 2016, Chevron led a consortium that was the successful bidder on an exploration license for Block 3 in the deepwater Perdido area of the Gulf of Mexico. Following license execution, expected by March 2017, the company will operate and hold a 33.3 percent working interest in Block 3, which covers 139,000 net acres.

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 a 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 2016 averaged 26,000 barrels per day, composed of 20,000 barrels of crude oil and 32 million cubic feet of natural gas.

Nonoperated development activities continued in 2016 at the Loma Campana concession in the Vaca Muerta Shale. During 2016, 58 horizontal wells were drilled, and the drilling program is expected to continue in 2017.

In 2016, an exploration program, which included one horizontal and three vertical wells, was completed in the nonoperated Narambuena Block. Results are under evaluation.

Brazil Chevron holds interests in the Frade (51.7 percent-owned and operated) and Papa-Terra (37.5 percent, nonoperated) deepwater fields located in the Campos Basin. The concession that includes the Frade Field expires in 2025, and the concession that includes the Papa-Terra Field expires in 2032. Net oil-equivalent production in 2016 averaged 16,000 barrels per day, composed of 16,000 barrels of crude oil and 5 million cubic feet of natural gas.

Additionally, Chevron holds a 50 percent-owned and operated interest in Block CE-M715, located in the Ceara Basin offshore Brazil. During 2016, the company completed acquisition of 3-D seismic data. Processing of the seismic data was completed in early 2017.

Colombia The company operates the offshore Chuchupa and the onshore Ballena natural gas fields and receives 43 percent of the production for the remaining life of each field. The company also received a variable production volume based on prior Chuchupa capital contributions through 2016. Net production in 2016 averaged 127 million cubic feet of natural gas per day.

Suriname After a farm-down in Block 42 in second quarter 2016, Chevron holds a 33.3 percent and a 50 percent nonoperated working interest in deepwater Blocks 42 and 45 offshore Suriname, respectively.

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, Dolphin Deep and Starfish natural gas fields. Net production in 2016 averaged 74 million cubic feet of natural gas per day.

Venezuela Chevron's production activities in Venezuela are performed by two affiliates in western Venezuela and an affiliate in the Orinoco Belt. Net oil-equivalent production during 2016 averaged 59,000 barrels per day, composed of 28,000 barrels of crude oil, 19 million cubic feet of natural gas and 28,000 barrels of synthetic oil upgraded from heavy oil.

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. Petropiar drilled 67 development wells in 2016. 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. Petroboscan drilled 33 development wells in 2016.

Chevron also holds a 34 percent interest in the Petroindependencia affiliate, which includes the Carabobo 3 heavy oil project located within the Orinoco Belt.

Africa

In Africa, the company is engaged in upstream activities in Angola, Democratic Republic of the Congo, Liberia, Morocco, Nigeria and Republic of Congo. Net oil-equivalent production averaged 389**,**000 barrels per day during 2016.

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. During 2016, net production averaged 108,000 barrels of liquids and 114 million cubic feet of natural gas per day.

Mafumeira Sul, the second development stage for the Mafumeira Field in Block 0, has a design capacity of 150,000 barrels of liquids and 350 million cubic feet of natural gas per day. Early production from the Mafumeira Sul Field commenced in October 2016 through a temporary production system. The main production facilities are expected to be completed and brought on line in first quarter 2017, and gas export to Angola LNG and water injection support are scheduled to begin in second quarter 2017. Ramp-up to full production is expected to continue through 2018.

Chevron has a 36.4 percent interest in Angola LNG Limited, which 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 byproduct of crude oil production. Feedstock for the plant originates from multiple fields and operators. In early 2016, work was completed on plant modifications and capacity and reliability enhancements. Production restarted and LNG cargos resumed in 2016. Total daily production in 2016 averaged 171 million cubic feet of natural gas (62 million net) and 7,000 barrels of NGLs (3,000 barrels net).

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. Gas flow to the Angola LNG Plant commenced in September 2016.

Angola-Republic of 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 Congo. Development drilling was completed at Lianzi in January 2016.

Democratic Republic of the Congo Chevron has a 17.7 percent nonoperated working interest in an offshore concession. Net production in 2016 averaged 2,000 barrels of crude oil per day.

Republic of 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 23,000 barrels of liquids per day in 2016.

In 2016, installation of a tension leg platform and a new FPU was completed and development drilling continued on the Moho Nord Project, located in the Moho-Bilondo development area. Total daily production in 2016 averaged 17,000 barrels of crude oil (5,000 barrels net).

Drilling on an exploration well in the Moho-Bilondo area was completed in January 2016, resulting in a crude oil discovery.

Liberia Chevron operates and holds a 45 percent interest in Block LB-14 off the coast of Liberia. Blocks LB-11 and LB-12 were relinquished in second quarter 2016.

Mauritania In June 2016, the company reassigned its interest in the C8, C12 and C13 contract areas offshore Mauritania to its partner.

Morocco After a farm-down in April 2016, the company holds a 45 percent interest in three operated deepwater areas offshore Morocco. The acquisition of 3-D seismic data in the Cap Cantin and Cap Walidia blocks was completed in 2016. The focus for 2017 is the evaluation of 3-D seismic data.

Nigeria Chevron holds a 40 percent interest in eight operated concessions 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. In 2016, the company's net oil-equivalent production in Nigeria averaged 235,000 barrels per day, composed of 204,000 barrels of crude oil, 159 million cubic feet of natural gas and 4,000 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. The first two phases of infill drilling, Agbami 2 and Agbami 3, are nearly completed, with the last of the 15 wells expected to come on line in second-half 2017. More locations for infill drilling have been identified, and an ongoing program is underway to further offset field decline. The leases that contain the Agbami Field expire in 2023 and 2024.

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 16.6 percent nonoperated working interest in the unitized area. The development plan involves subsea wells tied back to a floating production, storage and offloading vessel (FPSO). Spending is being paced until market conditions and reductions in project costs are sufficient to support the development of this project. At the end of 2016, no proved reserves were recognized for this project.

In deepwater exploration, Chevron operates and holds a 55 percent interest in the deepwater Nsiko discoveries in OML 140. The company plans to continue evaluating development options for the discoveries in the Nsiko area. Chevron also holds a 30 percent nonoperated working interest in OML 138, which includes the Usan Field and several satellite discoveries, and a 27 percent interest in adjacent licenses OML 139 and Oil Prospecting License (OPL) 223. In 2016, one exploratory well was drilled in OML 139 resulting in a crude oil discovery at the Owowo prospect. In 2017, the company plans to continue evaluating developments options for the multiple discoveries in the Usan area.

In the Niger Delta region, the company is the operator of the Escravos Gas Plant (EGP) with a total processing capacity of 680 million cubic feet per day of natural gas and an LPG and condensate export capacity of 58,000 barrels per day. The company is also the operator of the 33,000-barrel-per-day Escravos gas-to-liquids facility. Optimization of these facilities continued during 2016. Construction activities also progressed during 2016 on the 40 percent-owned and operated Sonam Field Development Project, which is designed to process natural gas through the EGP facilities and is expected to 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. Construction of offshore facilities continued in 2016. First production is expected in second-half 2017. Proved reserves have been recognized for the project.

In addition, the company holds a 36.7 percent interest in the West African Gas Pipeline Company Limited affiliate, which supplies Nigerian natural gas to customers in Benin, Ghana and Togo.

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, and Thailand. During 2016, net oil-equivalent production averaged 1,078,000 barrels per day.

Azerbaijan Chevron holds an 11.3 percent nonoperated interest in the Azerbaijan International Operating Company (AIOC) and the crude oil production from the Azeri-Chirag-Gunashli (ACG) fields. AIOC operations are conducted under a PSC that expires in 2024. Net oil-equivalent production in 2016 averaged 32,000 barrels per day, composed of 30,000 barrels of crude oil and 13 million cubic feet of natural gas.

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 (WREP), which is operated by AIOC. During 2016, WREP transported approximately 90,000 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 2016 averaged 410,000 barrels per day, composed of 322,000 barrels of liquids and 529 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 2016 from these fields averaged 263,000 barrels of crude oil, 375 million cubic feet of natural gas and 22,000 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.

The Future Growth and Wellhead Pressure Management Project (FGP/WPMP) at Tengiz is being managed as a single integrated project. The FGP is designed to increase total daily production by about 260,000 barrels of crude oil and to expand the utilization of sour gas injection technology proven in existing operations to increase ultimate recovery from the reservoir. The WPMP is designed to maintain production capacity and extend the production plateau from existing assets. The final investment decision for the FGP/WPMP was made in July 2016. Detailed design, fabrication, construction and mobilization activities are underway. First oil is planned for 2022. The initial recognition of proved reserves occurred in 2016 for the FGP. Proved reserves also have been recognized for the WPMP.

The Capacity and Reliability (CAR) Project is designed to reduce facility bottlenecks and increase plant capacity and reliability at Tengiz. Construction activities for the CAR Project progressed during 2016. Proved reserves have been recognized for the CAR Project.

The Karachaganak Field is located in northwest Kazakhstan, and operations are conducted under a PSC that expires in 2038. The development of the field is being conducted in phases. During 2016, net daily production averaged 37,000 barrels of liquids and 154 million cubic feet of natural gas. Most of the exported liquids were transported through the CPC pipeline. A portion was also exported via the Atyrau-Samara (Russia) Pipeline. The remaining liquids were sold into local and Russian markets. Work continues on identifying the optimal scope for the future expansion of the field. At year-end 2016, proved reserves had not been recognized for a future expansion.

Kazakhstan/Russia Chevron has a 15 percent interest in the CPC affiliate. During 2016, CPC transported an average of 959,000 barrels of crude oil per day, composed of 883,000 barrels per day from Kazakhstan and 76,000 barrels per day from Russia. In 2016, work continued on the expansion of the pipeline. By year-end 2016, capacity from Kazakhstan was increased to 1.0 million barrels per day. Additional capacity is scheduled to be added through mid-2017 to reach the design capacity of 1.4 million barrels per day. 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 in 2016 averaged 114,000 barrels per day, composed of 658 million cubic feet of natural gas and 4,000 barrels of condensate. The company has announced its intent to divest its assets in Bangladesh.

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. Net natural gas production in 2016 averaged 128 million cubic feet per day.

The Badamyar-Low Compression Platform is an expansion project in Block M5 designed to maintain production from the Yadana Field by lowering wellhead pressure. Fabrication activities progressed in 2016, and first production is expected in second quarter 2017. Proved reserves have been recognized for this project.

Chevron also holds a 99 percent-owned and operated interest in Block A5. Evaluation of a 3-D seismic survey that was completed in December 2015 continued in 2016.

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. Net oil-equivalent production in 2016 averaged 245,000 barrels per day, composed of 71,000 barrels of crude oil and condensate and 1.1 billion cubic feet of natural gas.

In the Pattani Basin, the development concept of the 35 percent-owned and operated Ubon Project includes facilities and wells to develop resources in Block12/27. Discussions with key stakeholders on future development plans are ongoing. At the end of 2016, proved reserves had not been recognized for this project.

During 2016, the company drilled two exploration and two delineation wells in the Pattani Basin, and all wells 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.

China Chevron has operated and nonoperated working interests in several areas in China. The company's net daily production in 2016 averaged 18,000 barrels of crude oil and 51 million cubic feet of natural gas.

The company operates the 49 percent-owned Chuandongbei Project, located onshore in the Sichuan Basin. The Xuanhan Gas Plant has three gas processing trains with a design outlet capacity of 258 million cubic feet per day. Production commenced from the Xuanhan Gas Plant in January 2016. Total daily production in 2016 averaged 111 million cubic feet of natural gas (51 million net).

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 Block 16/19 in the Pearl River Mouth Basin. The PSCs for these producing assets expire between 2022 and 2028.

Philippines The company holds a 45 percent nonoperated working interest in the Malampaya natural gas field, offshore Philippines. Net oil-equivalent production in 2016 averaged 26,000 barrels per day, composed of 138 million cubic feet of natural gas and 3,000 barrels of condensate.

Chevron holds a 40 percent interest in an affiliate that develops and produces onshore geothermal steam resources, 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 onshore Kalinga geothermal prospect area. In December 2016, the company signed an agreement to sell its geothermal interest in the Philippines. This transaction is expected to close in 2017.

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. Net oil-equivalent production in 2016 averaged 203,000 barrels per day, composed of 173,000 barrels of liquids and 182 million cubic feet of natural gas. In first quarter 2016, Chevron advised the government of Indonesia that it would not propose to extend the East Kalimantan PSC and intends to return the assets to the government upon PSC expiration in 2018. In December 2016, the company signed an agreement to sell its South Natuna Sea Block B assets. This transaction is expected to close in early 2017.

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. Infill drilling and workover programs continued in 2016.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 110 million cubic feet of natural gas and 4,000 barrels of condensate per day. The company's interest is 62 percent. Production from Bangka commenced in August 2016 and has reached full design capacity.

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, including extension of the associated PSCs, and securing new LNG sales contracts. At the end of 2016, proved reserves have not been recognized for this project.

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. In December 2016, the company signed an agreement to sell its geothermal assets in Indonesia. This transaction is expected to close in 2017.

Kurdistan Region of Iraq The company operates and holds 80 percent contractor interests in the Sarta and Qara Dagh PSCs. The company completed a second exploration well in the Sarta Block in early 2016. Further evaluation of the block is planned. For the Qara Dagh PSC, the results from seismic acquisition and evaluation in 2015 improved the company's understanding of the prospects, and the company is evaluating next steps.

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. Beginning in May 2015, production in the Partitioned Zone was shut in as a result of continued difficulties in securing work and equipment permits. As of early 2017, production remains shut-in, and the exact timing of a production restart is uncertain and dependent on dispute resolution between Saudi Arabia and Kuwait.

The shut-in also impacted plans for both the Wafra Steamflood Stage 1 Project, a full-field steamflood application in the Wafra Field First Eocene carbonate reservoir with a planned design capacity of 100,000 barrels of crude oil per day, and the Central Gas Utilization Project, a facility construction project intended to increase natural gas utilization while eliminating natural gas flaring at the Wafra Field. Both projects have been deferred pending dispute resolution between Saudi Arabia and Kuwait. At the end of 2016, proved reserves had not been recognized for these two projects.

In 2016, the company completed acquisition of a 3-D seismic survey covering the entire onshore Partitioned Zone. Processing of the newly acquired data is targeted to be completed in first-half 2017.

Australia/Oceania

In Australia/Oceania, the company is engaged in upstream activities in Australia and New Zealand. During 2016, net oil-equivalent production averaged 124,000 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 Bight Basin offshore South Australia. During 2016, the company's production averaged 21,000 barrels of liquids and 615 million cubic feet of natural gas per day.

Chevron holds a 47.3 percent interest in and is the operator of the Gorgon Project, which includes the development of the Gorgon and 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 gas plant, which are located on Barrow Island, off Western Australia. The total production capacity for the project is approximately 2.6 billion cubic feet of natural gas and 20,000 barrels of condensate per day. LNG Train 1 start-up and first cargo shipment were achieved in March 2016, and Train 2 start-up was achieved in October 2016. Total daily production in 2016 from the Gorgon Project averaged 348 million cubic feet of natural gas (165 million net) and 3,000 barrels of condensate (1,000 barrels net). Train 3 commissioning activities are progressing, and start-up is expected in second quarter 2017. The project's estimated economic life exceeds 40 years.

Chevron holds an 80.2 percent interest in the offshore licenses and a 64.1 percent interest in the LNG facilities associated with the Wheatstone Project. The project includes the development of the Wheatstone and Iago fields, a two-train, 8.9 million-metric-ton-per-year LNG facility, and a domestic gas plant. The onshore facilities are located at Ashburton North on the coast of Western Australia. The offshore portion of the project includes subsea infrastructure, an offshore platform and pipelines. 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. Drilling, completion and initial testing of all nine production wells is complete. All modules for LNG Trains 1 and 2 have been delivered to site and installed on their foundations. Commissioning of subsea, platform and plant facilities is underway in preparation for LNG Train 1 start-up in mid-2017. Start-up of Train 2 is expected approximately six to eight months after Train 1. Proved reserves have been recognized for this project. The project's estimated economic life exceeds 30 years from the time of start-up.

Chevron has a 16.7 percent nonoperated working interest in the North West Shelf (NWS) Venture in Western Australia. The concession for the NWS Venture expires in 2034.

Chevron monetizes its Australia natural gas resources on a portfolio basis. Most of the company’s LNG production from Australia is committed under binding long-term agreements with major utilities in Asia, with the remainder sold on the Asian spot LNG market. Chevron continues to leverage its global portfolio supply position to target additional short-to-medium term agreements to reduce its exposure to the Asian spot LNG market. Chevron also has binding long-term agreements for delivery of natural gas to customers in Western Australia and continues to market additional pipeline natural gas quantities from the projects.

During 2016, Chevron continued to evaluate future exploration potential in the Carnarvon Basin.

The company holds nonoperated working interests ranging from 24.8 percent to 50 percent in three exploration blocks in the Browse Basin.

The company operates and holds a 100 percent interest in offshore Blocks EPP44 and EPP45 in the Bight Basin. Processing and interpretation of the 3-D seismic data acquired in 2015 continued through 2016.

New Zealand Chevron holds a 50 percent interest and operates three deepwater exploration permits in the offshore Pegasus and East Coast basins. Acquisition of 2-D and 3-D seismic data commenced in late 2016 and is expected to be completed in second quarter 2017.

Europe

In Europe, the company is engaged in upstream activities in Denmark, Norway and the United Kingdom. Net oil-equivalent production averaged 86,000 barrels per day during 2016.

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. The concession expires in 2042. Net oil-equivalent production in 2016 averaged 22,000 barrels per day, composed of 14,000 barrels of crude oil and 48 million cubic feet of natural gas.

United Kingdom The company’s net oil-equivalent production in 2016 averaged 64,000 barrels per day, composed of 43,000 barrels of liquids and 122 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 nonoperated Britannia Field.

The 73.7 percent-owned and operated Alder Project was developed as a tieback 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. First gas was achieved in November 2016, and production reached design capacity by year-end.

The Captain Enhanced Oil Recovery Project is the next development phase of the Captain Field and is designed to increase field recovery by injecting a polymer/water mixture. Front-end engineering and design (FEED) activities continued to progress in 2016 and included a polymer injection pilot. The company also began an expansion of the existing polymer injection system on the wellhead production platform. The scope includes six new polymer injection wells and modifications to the platform facilities. At the end of 2016, proved reserves had not been recognized for this project.

During 2016, installation and hook-up activities progressed 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. First production is expected in 2018. 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 progress FEED activities for a 17-well subsea development tied back to an FPSO with natural gas exported via pipeline. 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 2016, proved reserves had not been recognized for this project.

Norway In May 2016, the company acquired a 20 percent nonoperated working interest in exploration Block PL 859, located in the Barents Sea. Evaluation of the acreage is ongoing.

Sales of Natural Gas and Natural Gas Liquids

The company sells natural gas and natural gas liquids (NGLs) 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 NGLs in connection with its supply and trading activities.

During 2016, U.S. and international sales of natural gas averaged 3 billion and 4.5 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 Angola, Australia, Bangladesh, Europe, Kazakhstan, Indonesia, Latin America, Myanmar, Nigeria, the Philippines and Thailand.

U.S. and international sales of NGLs averaged 145,000 and 85,000 barrels per day, respectively, in 2016. Substantially all of the international sales of NGLs from the company's producing interests are from operations in Angola, Australia, Canada, Indonesia, Nigeria and the United Kingdom.

Refer to “Selected Operating Data,” on page FS-12 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 2016, the company had a refining network capable of processing nearly 1.8 million barrels of crude oil per day. Operable capacity at December 31, 2016, and daily refinery inputs for 2014 through 2016 for the company and affiliate refineries are summarized in the table below.

Average crude oil distillation capacity utilization during 2016 was 92 percent, compared with 90 percent in 2015. At the U.S. refineries, crude oil distillation capacity utilization averaged 93 percent in 2016, compared with 96 percent in 2015. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 76 percent and 74 percent of Chevron's U.S. refinery inputs in 2016 and 2015, respectively.

In the United States, the company continued work on projects to improve refinery flexibility and reliability. At the Richmond, California refinery, the modernization project progressed with field construction activity restarted in 2016. At the Salt Lake City refinery, the company achieved a final investment decision on the alkylation retrofit project in September 2016, with construction expected to start in third quarter 2017. In November 2016, the company completed the sale of the Hawaii Refinery and related assets.

Outside the United States, the Singapore Refining Company, Chevron's 50 percent-owned joint venture, progressed construction of a gasoline desulfurization facility and a cogeneration plant. The utility systems and control center were fully commissioned in first quarter 2017, and Train 1 of the cogeneration plant is expected to be commissioned in second quarter 2017. This investment is expected to increase the refinery's capability to produce higher-value gasoline and improve energy efficiency. In addition, the company is evaluating sales of its refinery in British Columbia, Canada and its interests in the Cape Town Refinery in South Africa.

Petroleum Refineries: Locations, Capacities and Inputs

Capacities and inputs in thousands of barrels per day			**December 31, 2016**		**Refinery Inputs**	
Locations		**Number**	**Operable Capacity**	**2016**	**2015**	**2014**
Pascagoula	Mississippi	**1**	**330**	**355**	322	329
El Segundo	California	**1**	**291**	**267**	258	221
Richmond	California	**1**	**257**	**188**	245	229
Kapolei[1]	Hawaii	**—**	**—**	**37**	47	47
Salt Lake City	Utah	**1**	**53**	**53**	52	45
Total Consolidated Companies — United States		**4**	**931**	**900**	924	871
Map Ta Phut[2]	Thailand	**1**	**165**	**162**	164	141
Cape Town[3]	South Africa	**1**	**100**	**78**	69	72
Burnaby, B.C.	Canada	**1**	**55**	**51**	46	49
Total Consolidated Companies — International		**3**	**320**	**291**	279	262
Affiliates	Various Locations	**3**	**542**	**497**	499	557
Total Including Affiliates — International		**6**	**862**	**788**	778	819
Total Including Affiliates — Worldwide		**10**	**1,793**	**1,688**	1,702	1,690

1 In November 2016, the company sold the Hawaii Refinery.

2 Chevron holds a 60.6 percent controlling interest in the Star Petroleum Refining Public Company Limited.

3 Chevron holds a 75 percent 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 the remaining 25 percent.

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, 2016.

Refined Products Sales Volumes

Thousands of barrels per day	**2016**	**2015**	**2014**
United States			
Gasoline	**631**	621	615
Jet Fuel	**242**	232	222
Gas Oil and Kerosene	**182**	215	217
Residual Fuel Oil	**59**	59	63
Other Petroleum Products[1]	**99**	101	93
Total United States	**1,213**	1,228	1,210
International[2]			
Gasoline	**382**	389	403
Jet Fuel	**261**	271	249
Gas Oil and Kerosene	**468**	478	498
Residual Fuel Oil	**144**	159	162
Other Petroleum Products[1]	**207**	210	189
Total International	**1,462**	1,507	1,501
Total Worldwide[2]	**2,675**	2,735	2,711

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

[2] Includes share of affiliates' sales:	**377**	420	475

In the United States, the company markets under the Chevron and Texaco brands. At year-end 2016, the company supplied directly or through retailers and marketers approximately 7,800 Chevron- and Texaco-branded motor vehicle service stations, primarily in the southern and western states. Approximately 325 of these outlets are company-owned or -leased stations.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 6,000 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 the Middle East, 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. The company completed the sale of its New Zealand marketing and lubricants operations in June 2016. The company is evaluating the sale of its marketing and lubricants businesses in southern Africa. In addition, the company is evaluating the sale of its marketing assets in British Columbia and Alberta, Canada.

Chevron markets commercial aviation fuel at approximately 100 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 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 2016, the company manufactured, blended or conducted research at 11 locations around the world. In 2016, the company progressed construction on a carboxylate plant in Singapore, which is scheduled to be completed in fourth quarter 2017. In 2016, design work continued for a planned manufacturing plant in Ningbo, China, with a final investment decision expected in 2018.

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 2016, CPChem owned or had joint-venture interests in 32 manufacturing facilities and two research and development centers around the world.

During 2016, construction activities continued on the U.S. Gulf Coast Petrochemicals Project, which is expected to capitalize on advantaged feedstock sourced from shale resource 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. The polyethylene units are expected to start up mid-2017, and the ethane cracker in late 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 base chemicals are used to produce a range of products, including adhesives, plastics and textile fibers. GS Caltex also produces polypropylene, which is used to make automotive and home appliance parts, food packaging, laboratory equipment, and textiles.

Transportation

Pipelines Chevron owns and operates a network of crude oil, natural gas and product 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.

Refer to pages 12 and 13 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 in the coastal waters of the United States. The foreign-flagged vessels transport crude oil, LNG, refined products and feedstocks in support of the company's global Upstream and Downstream businesses.

Four of the scheduled six new LNG carriers in support of the developing LNG portfolio are in service, with the final two scheduled for delivery in 2017.

Other Businesses

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, cybersecurity and network technology to provide a digital infrastructure to enable Chevron’s global operations and business processes.

Chevron's technology ventures company supports Chevron's upstream and downstream businesses by bridging the gap between business unit needs and emerging technology solutions developed externally in areas of emerging materials, water management, information technology, power systems and production enhancement.

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 28 beginning on page FS-63 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, which has the objective to further develop the industry’s capability to contain and shut in subsea well control incidents in different regions of the world.

The company is committed to improving energy efficiency in its day-to-day operations and is required to comply with the greenhouse gas-related laws and regulations to which it is subject. Refer to Item 1A. Risk Factors on pages 20 through 22 for further discussion of greenhouse gas regulation and climate change and the associated risks to Chevron’s business.

Refer to Management's Discussion and Analysis of Financial Condition and Results of Operations on page FS-18 for additional information on environmental matters and their impact on Chevron, and on the company's 2016 environmental expenditures. Refer to page FS-18 and Note 25 on page FS-61 for a discussion of environmental remediation provisions and year-end reserves.

Item 1A. Risk Factors

Chevron is a global energy company and its operating and financial results are subject to a variety of risks inherent in the global oil, gas, and petrochemical businesses. Many of these risks are not within the company's control and could materially impact the company’s results of operations and 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, technology advancements, production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries (OPEC), weather-related damage and disruptions, competing fuel prices, and geopolitical risks. Chevron evaluates the risk of changing commodity prices as part of its business planning process. An investment in the company carries significant exposure to fluctuations in global crude oil prices.

Extended periods of low prices for crude oil can have a material adverse impact on the company's results of operations, financial condition and liquidity. Among other things, the company’s upstream earnings, cash flows, and capital and exploratory expenditure programs could be negatively affected, as could its production and proved reserves. Upstream assets may also become impaired. Downstream earnings could be negatively affected because they depend upon the supply and demand for refined products and the associated margins on refined product sales. A significant or sustained decline in liquidity could adversely affect the company’s credit ratings, potentially increase financing costs and reduce access to debt markets. The company may be unable to realize anticipated cost savings, expenditure reductions and asset sales that are intended to compensate for such downturns. In some cases, liabilities associated with divested assets may return to the company when an acquirer of those assets subsequently declares bankruptcy. In addition, extended periods of low commodity prices can have a material adverse impact on the results of operations, financial condition and liquidity of the company’s suppliers, vendors, partners and equity affiliates upon which the company’s own results of operations and financial condition depends.

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 it 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 causes beyond its control Chevron operates in both urban areas and remote and sometimes inhospitable regions. The company’s operations are therefore subject to disruption from natural or human causes beyond its control, including physical risks from hurricanes, severe storms, floods and other forms of severe weather, war, accidents, civil unrest, 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's risk management systems are designed to assess potential physical and other risks to its operations and assets and to plan for their resiliency. While capital investment reviews and decisions incorporate 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, it is difficult to predict with certainty 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.

Cyberattacks targeting Chevron’s process control networks or other digital infrastructure could have a material adverse impact on the company’s business and results of operations There are numerous and evolving risks to cybersecurity and privacy from cyber threat actors, including criminal hackers, state-sponsored intrusions, industrial espionage and employee malfeasance. Although Chevron devotes significant resources to prevent unwanted intrusions and to protect its systems and data, the company has experienced and will continue to experience cyber incidents of varying degrees in the conduct of its business. Cyber threat actors could compromise the company’s process control networks or other critical systems and infrastructure, resulting in disruptions to its business operations, injury to people, harm to the environment or assets, access to its financial reporting systems, or loss, misuse or corruption of critical data and proprietary information, including intellectual property, business information and that of its employees, customers, partners and other third parties. Cyber events could result in significant financial losses, legal or regulatory violations, reputational harm, and legal liability and could ultimately have a material adverse effect on the company’s business and results of operations.

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 impair our ability to operate and 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, processes and systems, 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 18 to the Consolidated Financial Statements, beginning on page FS-45.

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 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, state or local environmental regulations or laws, including those designed to stop or impede the development or production of oil and gas, such as those related to the use of hydraulic fracturing or bans on drilling, could adversely affect the company's current or anticipated future operations and profitability.

Regulation of greenhouse gas (GHG) emissions could increase Chevron's operational costs and reduce demand for Chevron's hydrocarbon and other products In the years ahead, companies in the energy industry, like Chevron, may be challenged by an increase in international and domestic regulation relating to GHG emissions. Such regulation could have the impact of curtailing profitability in the oil and gas sector or rendering the extraction of the company's oil and gas resources economically infeasible. Although the IEA's World Energy Outlook scenarios anticipate global demand for oil to continue increasing until 2040, and even GHG-constrained scenarios (such as the IEA's 450 case) anticipate significant demand for petroleum and natural gas given their respective advantages in transportation and power generation, if a new onset of regulation contributes to a decline in the demand for the company's products, this could have a material adverse effect on the company and its financial condition.

International agreements (e.g., the Paris Agreement and the Kyoto Protocol) and national (e.g., carbon tax, cap-and-trade or efficiency standards), regional and state legislation (e.g., California AB32 and SB32; low carbon fuel standards) and regulatory measures (e.g., the U.S. Environmental Protection Agency's methane performance standards) that aim to limit or reduce GHG emissions are currently in various stages of implementation. For example, the Paris Agreement went into effect in November 2016, and a number of countries are adopting policies to meet their Paris Agreement goals. In the United States, the company has been complying with currently implemented programs such as the federal Renewable Fuel Standard program, and related volume standards, and state regulations such as California AB32, including the cap-and-trade program and related low carbon fuel standard obligations. Follow-on legislation to California AB32, known as California SB32, was signed into law in 2016, with effect in 2020, and is currently in the scoping plan phase. Separately, other states and localities have also sought to directly regulate GHG emissions through mechanisms such as, for example, a carbon tax. Many of the foregoing are still in a proposal stage and others face legal challenge or legislative efforts to be repealed or significantly reformed. Thus, even with respect to existing regulatory compliance obligations, the landscape continues to be in a state of constant re-assessment and legal challenge, making it difficult to predict with certainty the ultimate impact that such regulations will have on the company.

GHG emissions-related laws and related regulations and the effects of operating in a potentially carbon-constrained environment may result in increased and substantial capital, compliance, operating and maintenance costs and could, among other things, reduce demand for hydrocarbons and the company’s hydrocarbon-based products, make the company’s products more expensive, adversely affect the economic feasibility of the company’s resources, and adversely affect the company’s sales volumes, revenues and margins. GHG emissions (e.g., carbon dioxide and methane) that could be regulated include, among others, those associated with the company’s exploration and production of hydrocarbons such as 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 hydrocarbon 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 hydrocarbon products. Many 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. In addition, increasing attention to climate change risks has resulted in an increased possibility of governmental investigations and, potentially, private litigation against the company.

Consideration of GHG issues and the responses to those issues through international agreements and national, regional or state legislation or regulations are integrated into the company’s strategy and planning, capital investment reviews, and risk management tools and processes, where applicable. They are also factored into the company’s long-range supply, demand and energy price forecasts. These forecasts reflect long-range effects from renewable fuel penetration, energy efficiency standards, climate-related policy actions, and demand response to oil and natural gas prices. Additionally, the company assesses carbon pricing risks by considering carbon costs in these forecasts. The actual level of expenditure required to comply with new or potential climate change-related laws and regulations and amount of additional investments in new or existing technology or facilities, such as carbon dioxide injection, is difficult to predict with certainty and is expected to vary depending on the actual laws and regulations enacted in a jurisdiction, the company’s activities in it and market conditions.

The ultimate effect of international agreements and national, regional and state legislation and regulatory measures to limit GHG emissions on the company’s financial performance, and the timing of these effects, will depend on a number of factors. Such factors include, among others, the sectors covered, the greenhouse gas emissions reductions required, 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 extent to which the company is able to recover the costs incurred through the pricing of the company’s products in the competitive marketplace. Further, the ultimate impact of GHG emissions-related agreements, legislation and measures on the company’s financial performance is highly uncertain because the company is unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

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 impairments to property, plant and equipment; estimates of crude oil and natural gas recoverable reserves; accruals for estimated liabilities, including litigation reserves; and measurement of benefit obligations for pension and other postretirement benefit plans. 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-65 through FS-75. Note 17, “Properties, Plant and Equipment,” to the company’s financial statements is on page FS-44.

Item 3. Legal Proceedings

Governmental Proceedings As initially disclosed in the Annual Report on Form 10-K for the year ended December 31, 2013, on August 6, 2012, a piping failure and fire occurred at the Chevron refinery in Richmond, California. Various federal, state, and local agencies initiated investigations as a result of the incident. Based on a civil investigation conducted pursuant to its authority under the Clean Air Act Risk Management Plan program (RMP), the United States Environmental Protection Agency (EPA) issued alleged findings of violation to Chevron’s Richmond refinery on December 17, 2013. The California Division of Occupational Safety and Health (Cal/OSHA) also issued citations related to the incident. Following the Richmond fire, EPA conducted RMP inspections at Chevron’s El Segundo, California; Pascagoula, Mississippi; Kapolei, Hawaii; and Salt Lake City, Utah refineries. With the participation of the United States Department of Justice, Chevron and EPA are negotiating a potential combined resolution that may include all of EPA’s alleged findings of violation related to the Richmond fire and subsequent RMP inspections. Resolution of the alleged findings of violation may result in the payment of a civil penalty of $100,000 or more. Chevron and Cal/OSHA are separately negotiating a potential resolution of Cal/OSHA’s citations related to the incident.

Chevron facilities within the jurisdiction of California’s South Coast Air Quality Management District (SCAQMD) currently have multiple outstanding Notices of Violation (NOVs) issued by SCAQMD. Resolution of the alleged violations may result in the payment of a civil penalty of $100,000 or more. As initially disclosed in the Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, in April 2016, Chevron received a proposal from the SCAQMD seeking to collectively resolve certain NOVs issued in 2012 and 2013 to Chevron’s El Segundo refinery. Subsequently, the SCAQMD provided notice to Chevron that it was also seeking to resolve certain NOVs issued to the refinery in 2014. Chevron and the SCAQMD are negotiating a potential combined resolution of the 2012-2014 NOVs. Collective resolution of these NOVs may result in the payment of a civil penalty of $100,000 or more.

Chevron facilities within the jurisdiction of California’s Bay Area Air Quality Management District (BAAQMD) currently have multiple outstanding NOVs issued by BAAQMD. Resolution of the alleged violations may result in the payment of a civil penalty of $100,000 or more. On December 7, 2016, Chevron received a proposal from the BAAQMD seeking to collectively resolve certain NOVs issued in 2013-2015 to Chevron’s Richmond refinery and to Chevron’s Richmond, California and San Jose, California marketing terminals. Chevron and the BAAQMD are negotiating a potential combined resolution of the 2013-2015 NOVs. Collective resolution of these NOVs may result in the payment of a civil penalty of $100,000 or more.

On December 5, 2016, Chevron received a NOV from the California Air Resources Board (CARB) alleging that for compliance years 2011-2015, Chevron failed to deduct some exported volumes of fuel from the sales that must be reported under the state’s Low Carbon Fuel Standard (LCFS) program. The allegation is that Chevron purchased and retired more LCFS credits than were required. Chevron and CARB are negotiating a potential resolution of the alleged violation. Resolution of this NOV may result in the payment of a civil penalty of $100,000 or more.

Other Proceedings Information related to other legal proceedings, including Ecuador, is included beginning on page FS-45 in Note 18 to the Consolidated Financial Statements.

Item 4. Mine Safety Disclosures

Not applicable.

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-22.

Chevron Corporation Issuer Purchases of Equity Securities for Quarter Ended December 31, 2016

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, 2016	169	$102.44	—	—
Nov. 1 – Nov. 30, 2016	—	—	—	—
Dec. 1 – Dec. 31, 2016	2,840	$113.29	—	—
Total Oct. 1 – Dec. 31, 2016	**3,009**	**$112.68**	**—**	**—**

1 Includes common shares repurchased from company employees and directors 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 and director stock options. The options were issued to and exercised by management under Chevron long-term incentive 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. From inception of the program through 2014, the company had purchased 180,886,291 shares 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 did not acquire any shares under the program in 2015 or 2016.

Item 6. Selected Financial Data

The selected financial data for years 2012 through 2016 are presented on page FS-64.

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-16 and in Note 11 to the Consolidated Financial Statements, "Financial and Derivative Instruments," beginning on page FS-38.

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, management concluded that the company's disclosure controls and procedures were effective as of December 31, 2016.

(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) and 15d-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, 2016.

The effectiveness of the company's internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included on page FS-24.

(c) Changes in Internal Control Over Financial Reporting During the quarter ended December 31, 2016, 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.

Item 9B. Other Information

Rule 10b5-1 Plan Elections

R. Hewitt Pate, Vice President and General Counsel, entered into a pre-arranged stock trading plan in November 2016. Mr. Pate's plan provides for the potential exercise of vested stock options and the associated sale of up to 51,000 shares of Chevron common stock between February 2017 and November 2017.

This trading plan was entered into during an open insider trading window and is intended to satisfy Rule 10b5-1(c) of the Securities Exchange Act of 1934, as amended, and Chevron's policies regarding transactions in Chevron securities.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers of the Registrant at February 23, 2017

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	60	Chairman of the Board and Chief Executive Officer (since 2010)	Chairman of the Board and Chief Executive Officer
M.K. Wirth	56	Vice Chairman of the Board and Executive Vice President (since February 2017) Executive Vice President, Midstream and Development (February 2016 through January 2017) Executive Vice President, Downstream (2006 through 2015)	Corporate Strategy; Corporate Business Development; Policy, Government and Public Affairs; Supply and Trading Activities; Shipping; Pipeline; Power and Energy Management
J.W. Johnson	57	Executive Vice President, Upstream (since 2015) Senior Vice President, Upstream (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	52	Executive Vice President, Downstream (since 2016) Corporate Vice President and President, Gas and Midstream (2014 through 2015) 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 Refining, Marketing and Lubricants; Chemicals
J.C. Geagea	57	Executive Vice President, Technology, Projects and Services (since 2015) Senior Vice President, Technology, Projects and Services (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
P.E. Yarrington	60	Vice President and Chief Financial Officer (since 2009)	Finance
R.H. Pate	54	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 2017 Annual Meeting of Stockholders and 2017 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 2017 Annual Meeting (the "2017 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 2017 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 2017 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 2017 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

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 2017 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 2017 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 2017 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 2017 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 2017 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 2017 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 2017 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 2017 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 PricewaterhouseCoopers LLP as the Independent Registered Public Accounting Firm for 2017" in the 2017 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	**2016**	2015	2014
Employee Termination Benefits			
Balance at January 1	**$ 308**	$ 49	$ 14
Additions (reductions) charged to expense	**160**	342	53
Payments	**(357)**	(83)	(18)
Balance at December 31	**$ 111**	$ 308	$ 49
Allowance for Doubtful Accounts			
Balance at January 1	**$ 429**	$ 194	$ 95
Additions to expense	**76**	251	119
Bad debt write-offs	**(18)**	(16)	(20)
Balance at December 31	**$ 487**	$ 429	$ 194
Deferred Income Tax Valuation Allowance*			
Balance at January 1	**$ 15,412**	$ 16,292	$ 17,171
Additions to deferred income tax expense	**1,810**	1,440	1,192
Reduction of deferred income tax expense	**(1,153)**	(2,320)	(2,071)
Balance at December 31	**$ 16,069**	$ 15,412	$ 16,292

* See also Note 19 to the Consolidated Financial Statements, beginning on page FS-49.

Item 16. Form 10-K Summary

Not applicable.

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 23rd day of February, 2017.

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 23rd day of February, 2017.

Principal Executive Officer
(and Director)

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

Principal Financial Officer

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

Principal Accounting Officer

/s/ JEANETTE L. OURADA
Jeanette L. Ourada, Vice President
and Comptroller

*By: /s/ MARY A. FRANCIS
Mary A. Francis,
Attorney-in-Fact

Directors

WANDA M. AUSTIN*
Wanda M. Austin

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 IV*
Charles W. Moorman IV

DAMBISA F. MOYO*
Dambisa F. Moyo

RONALD D. SUGAR*
Ronald D. Sugar

INGE G. THULIN*
Inge G. Thulin

/s/ MICHAEL K. WIRTH
Michael K. Wirth, Vice Chairman
of the Board and
Executive Vice President

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FS-2

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

FS-21

Consolidated Financial Statements

FS-28

Notes to the Consolidated Financial Statements

Key Financial Results

Millions of dollars, except per-share amounts		**2016**		2015		2014
Net Income (Loss) Attributable to Chevron Corporation	**$**	**(497)**	$	4,587	$	19,241
Per Share Amounts:						
Net Income (Loss) Attributable to Chevron Corporation						
– Basic	**$**	**(0.27)**	$	2.46	$	10.21
– Diluted	**$**	**(0.27)**	$	2.45	$	10.14
Dividends	**$**	**4.29**	$	4.28	$	4.21
Sales and Other Operating Revenues	**$**	**110,215**	$	129,925	$	200,494
Return on:						
Capital Employed		**(0.1)%**		2.5%		10.9%
Stockholders' Equity		**(0.3)%**		3.0%		12.7%

Earnings by Major Operating Area

Millions of dollars		**2016**		2015		2014
Upstream						
United States	**$**	**(2,054)**	$	(4,055)	$	3,327
International		**(483)**		2,094		13,566
Total Upstream		**(2,537)**		(1,961)		16,893
Downstream						
United States		**1,307**		3,182		2,637
International		**2,128**		4,419		1,699
Total Downstream		**3,435**		7,601		4,336
All Other		**(1,395)**		(1,053)		(1,988)
Net Income (Loss) Attributable to Chevron Corporation[1,2]	**$**	**(497)**	$	4,587	$	19,241
[1] Includes foreign currency effects:	**$**	**58**	$	769	$	487

[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-6 for a discussion of financial results by major operating area for the three years ended December 31, 2016.

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 Congo, Singapore, South Africa, South Korea, Thailand, Trinidad and Tobago, the United Kingdom, the United States, and Venezuela.

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 persistently high global crude oil inventories and production. 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, leverage, capital and exploratory investment program and production outlook. The company is responding with reductions in operating expenses, including employee reductions, pacing and re-focusing of capital and exploratory expenditures , and increased 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 increase is unknown. In the company's downstream business, crude oil is the largest cost component of refined products. It is the company's objective to deliver competitive results and shareholder value in any business environment.

The effective tax rate for the company can change substantially during periods of significant earnings volatility. This is due to the mix effects that are impacted both by the absolute level of earnings or losses and whether they arise in higher or lower tax rate jurisdictions. As a result, a decline or increase in the effective income tax rate in one period may not be indicative of expected results in future periods. Note 19 provides the company's effective income tax rate for the last three years.

Refer to the "Cautionary Statement Relevant to Forward-Looking Information" on page 2 and to "Risk Factors" in Part I, Item 1A, on pages 20 through 22 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

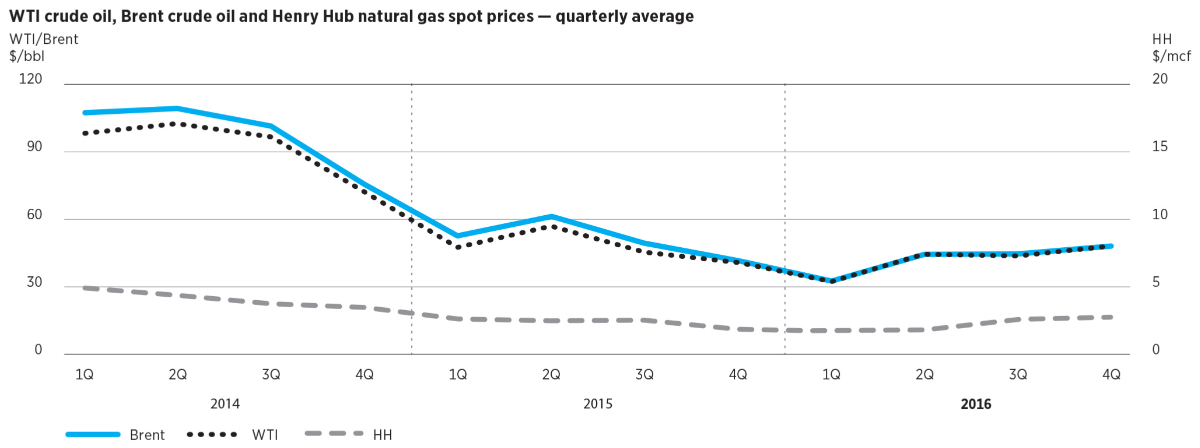
value growth. Refer to the "Results of Operations" section beginning on page FS-6 for discussions of net gains on asset sales during 2016. Asset dispositions and restructurings may also occur in future periods and could result in significant gains or losses.

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

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

Upstream Earnings for the upstream segment are closely aligned with industry prices for crude oil and natural gas. Crude oil and natural gas prices are subject to external factors over which the company has no control, including product demand connected with global economic conditions, industry inventory levels, technology advancements, production quotas or other actions imposed by the Organization of Petroleum Exporting Countries (OPEC), actions of regulators, 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. As a result of the decline in prices of crude oil and other commodities since mid-2014, these costs have declined. Capital and exploratory expenditures and operating expenses can also be affected by damage to production facilities caused by severe weather or civil unrest, delays in construction, or other factors.



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 $44 per barrel for the full-year 2016, compared to $52 in 2015. As of mid-February 2017, the Brent price was $55 per barrel. The majority of the company's equity crude production is priced based on the Brent benchmark. Crude oil prices remained low through much of 2016, but increased modestly late in the year after OPEC announced production cuts. On November 30, 2016, OPEC agreed to cap production at 32.5 million barrels per day starting in January 2017.

The WTI price averaged $43 per barrel for the full-year 2016, compared to $49 in 2015. As of mid-February 2017, the WTI price was $53 per barrel. WTI traded at a discount to Brent for much of 2016 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 relative supply/demand balances for each crude type, which are functions of the capacity of refineries that are able to process each as feedstock into high-value light products (motor gasoline, jet fuel, aviation gasoline and diesel fuel). In second-half 2016, the differential held generally steady in North America as robust refinery demand supported heavy crude values, while light sweet crude prices in the U.S. were supported by slowing domestic production. Outside of North America, differentials were steady to slightly wider amid well-supplied light sweet crude markets in the Atlantic Basin, while continued robust Middle East exports and rising Iranian production kept pressure on heavier, more sour crudes. Differentials widened in December as light sweet crude values benefited more from the announced OPEC deal.

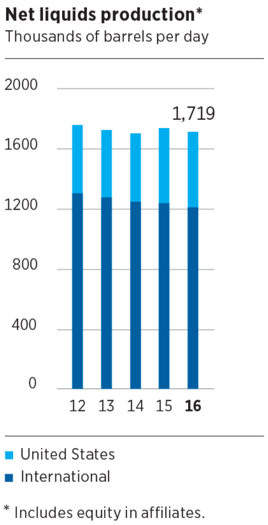
Chevron produces or shares in the production of heavy crude oil in California, Indonesia, the Partitioned Zone between Saudi Arabia and Kuwait, Venezuela and in certain fields in Angola, China and the United Kingdom sector of the North Sea. (See page FS-12 for the company’s average U.S. and international crude oil realizations.)

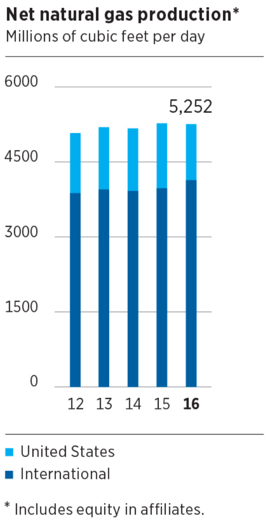
In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply-and-demand conditions in those markets. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced and stored in North America. In the United States, prices at Henry Hub averaged $2.46 per thousand cubic feet (MCF) during 2016, compared with $2.62 during 2015. As of mid-February 2017, the Henry Hub spot price was $2.86 per MCF.

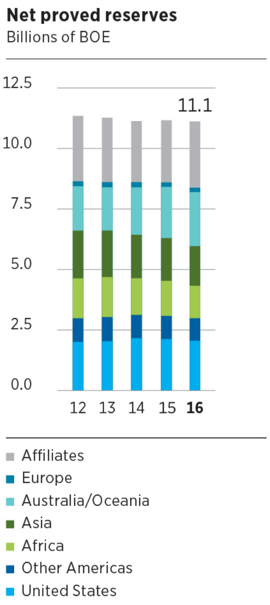
Outside the United States, price changes for natural gas depend on a wide range of supply, demand and regulatory circumstances. Chevron sells natural gas into the domestic pipeline market in most locations. In some locations, Chevron continues to invest in long-term projects to install infrastructure to produce and liquefy natural gas for transport by tanker to other markets. The company's long-term contract prices for liquefied natural gas (LNG) are typically linked to crude oil prices. Most of the equity LNG offtake from the operated Australian LNG projects is committed under binding long-term contracts, with the remainder to be sold in the Asian spot LNG market. The Asian spot market reflects the supply and demand for LNG in the Pacific Basin and is not directly linked to crude oil prices. International natural gas realizations averaged $4.02 per MCF during 2016, compared with $4.53 per MCF during 2015. (See page FS-12 for the company’s average natural gas realizations for the U.S. and international regions.)

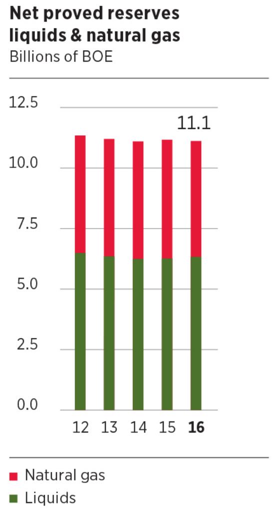
The company’s worldwide net oil-equivalent production in 2016 averaged 2.594 million barrels per day. About one-sixth of the company’s net oil-equivalent production in 2016 occurred in the OPEC-member countries of Angola, Nigeria and Venezuela. OPEC quotas had no effect on the company’s net crude oil production in 2016 or 2015.

The company estimates that net oil-equivalent production in 2017 will grow 4 to 9 percent compared to 2016, assuming a Brent crude oil price of $50 per barrel and before the effect of anticipated asset sales. The impact of 2017 asset sales on full-year production is expected to be in the range of 50,000 to 100,000 barrels of oil-equivalent per day, depending on the timing of the close of individual transactions. This estimate is subject to many factors and uncertainties, including the duration of the low price environment that began in second-half 2014; quotas or other actions 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.









In the Partitioned Zone between Saudi Arabia and Kuwait, production was shut-in beginning in May 2015 as a result of difficulties in securing work and equipment permits. Net oil-equivalent production in the Partitioned Zone in 2014 was 81,000 barrels per day. During 2015, net oil-equivalent production averaged 28,000 barrels per day. As of early 2017, production remains shut in and the exact timing of a production restart is uncertain and dependent on dispute resolution between Saudi Arabia and Kuwait. The financial effects from the loss of production in 2016 were not significant and are not expected to be significant in 2017.

Net proved reserves for consolidated companies and affiliated companies totaled 11.1 billion barrels of oil-equivalent at year-end 2016, down slightly from year-end 2015. The reserve replacement ratio in 2016 was 95 percent. Refer to Table V beginning on page FS-69 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2014 and each year-end from 2014 through 2016, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2016.

Refer to the "Results of Operations" section on pages FS-6 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-6 through FS-9 for additional discussion of the company's downstream operations.

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

Operating Developments

Key operating developments and other events during 2016 and early 2017 included the following:

Upstream

Angola Restarted LNG production and cargo shipments at the Angola LNG plant.

Australia Achieved start-up of Trains 1 and 2 at the Gorgon Project and progressed commissioning of Train 3.

Progressed commissioning and testing of subsea and platform facilities and production wells at the Wheatstone Project. Progressed commissioning of LNG Train 1 and common facilities, and received and installed all Train 2 modules at the site.

Indonesia Commenced production at the Bangka Field, the first stage of the Indonesia Deepwater Development.

Reached agreement to sell the company's geothermal assets.

Kazakhstan Announced final investment decision on the Future Growth and Wellhead Pressure Management Project at the company's 50 percent-owned affiliate, Tengizchevroil, which is expected to increase crude oil production at the Tengiz Field by about 260,000 barrels per day and maintain production levels as reservoir pressure declines.

Philippines Reached agreement to sell the company's geothermal assets.

United Kingdom Announced first gas from the Alder Field in the Central North Sea.

Downstream

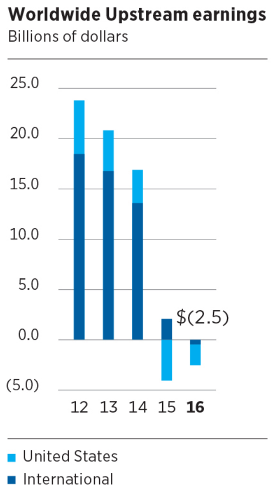
Completed the sales of the company's marketing and lubricants assets in New Zealand, and its refining and marketing assets in Hawaii.

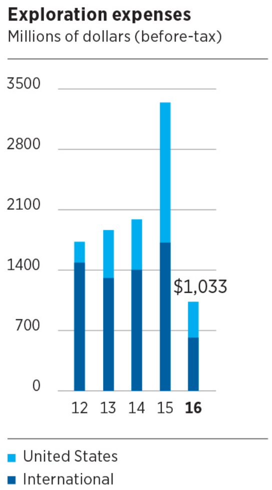
Other

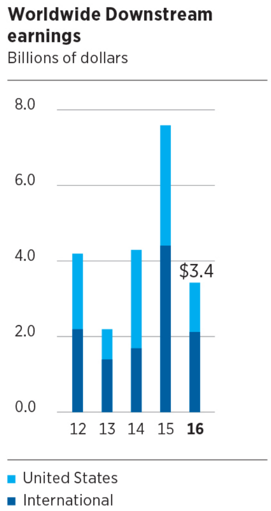
Common Stock Dividends The quarterly common stock dividend was increased by $0.01 per share in October 2016, making 2016 the 29th consecutive year that the company increased its annual dividend payout.

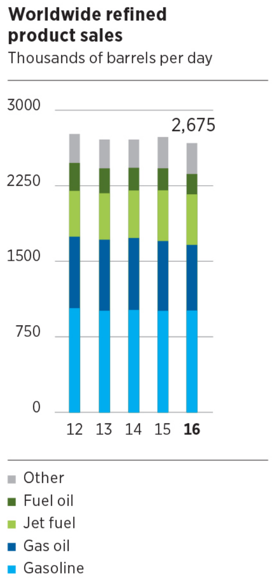
Results of Operations

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 15, beginning on page FS-40, 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-6.









U.S. Upstream

Millions of dollars		**2016**		2015		2014
Earnings	**$**	**(2,054)**	$	(4,055)	$	3,327

U.S. upstream operations incurred a loss of $2.05 billion in 2016 compared to a loss of $4.06 billion in 2015. The improvement was due to lower depreciation expense of $1.2 billion and lower exploration expense of $780 million primarily reflecting a decrease in impairments and project cancellations. Also contributing to the improvement were lower operating expenses of $600 million and lower tax items of $190 million. Partially offsetting these effects were lower crude oil and natural gas realizations of $920 million.

U.S. upstream operations incurred a loss of $4.06 billion in 2015 compared to earnings of $3.33 billion from 2014. The decrease was primarily due to lower crude oil and natural gas realizations of $4.86 billion and $570 million, respectively, higher depreciation expenses of $2.19 billion, and higher exploration expenses of $650 million. The increase in depreciation and exploration expenses was primarily due to impairments and project cancellations. Lower gains on asset sales also contributed to the decrease with 2015 gains of $110 million compared with $700 million in 2014. Partially offsetting these effects were higher crude oil production of $900 million and lower operating expenses of $450 million.

The company’s average realization for U.S. crude oil and natural gas liquids in 2016 was $35.00 per barrel, compared with $42.70 in 2015 and $84.13 in 2014. The average natural gas realization was $1.59 per thousand cubic feet in 2016, compared with $1.92 in 2015 and $3.90 in 2014.

Net oil-equivalent production in 2016 averaged 691,000 barrels per day, down 4 percent from 2015 and up 4 percent from 2014. Between 2016 and 2015, production increases from shale and tight properties in the Permian Basin in Texas and New Mexico, and base business were more than offset by the effect of asset sales and normal field declines. Between 2015 and 2014, production increases due to project ramp-ups in the Gulf of Mexico and the Permian Basin in Texas and New Mexico were partially offset by the effect of asset sales and normal field declines.

The net liquids component of oil-equivalent production for 2016 averaged 504,000 barrels per day, up 1 percent from 2015 and 11 percent from 2014. Net natural gas production averaged about 1.1 billion cubic feet per day in 2016, down 15 percent from 2015 and 10 percent from 2014, primarily as a result of asset sales. Refer to the “Selected Operating Data” table on page FS-12 for a three-year comparison of production volumes in the United States.

International Upstream

Millions of dollars		**2016**		2015		2014
Earnings*	**$**	**(483)**	$	2,094	$	13,566
*Includes foreign currency effects:	**$**	**122**	$	725	$	597

International upstream incurred a loss of $483 million in 2016 compared with earnings of $2.09 billion in 2015. The decrease in earnings was primarily due to lower crude oil realizations of $1.89 billion, lower natural gas realizations of $600 million, lower gains on asset sales of $450 million and higher tax items of $330 million. Partially offsetting the decrease were lower exploration and operating expenses of $640 million and $520 million, respectively, and higher natural gas sales volumes of $330 million. Foreign currency effects increased earnings by $122 million in 2016 compared with an increase of $725 million a year earlier.

International upstream earnings were $2.09 billion in 2015 compared with $13.57 billion in 2014. The decrease between periods was primarily due to lower crude oil and natural gas realizations of $10.57 billion and $880 million, respectively, and higher depreciation expenses of $1.11 billion, primarily reflecting impairments. Lower gains on asset sales also contributed to the decrease with gains of $370 million in 2015 compared with $1.10 billion in 2014. Partially offsetting the decrease were higher crude oil sales volumes of $590 million and lower operating expenses of $510 million. Foreign currency effects increased earnings by $725 million in 2015, compared with an increase of $597 million a year earlier.

The company’s average realization for international crude oil and natural gas liquids in 2016 was $38.61 per barrel, compared with $46.52 in 2015 and $90.42 in 2014. The average natural gas realization was $4.02 per thousand cubic feet in 2016, compared with $4.53 and $5.78 in 2015 and 2014, respectively.

International net oil-equivalent production was 1.90 million barrels per day in 2016, essentially unchanged from 2015 and 2014. Between 2016 and 2015, production increases from major capital projects, base business, and shale and tight properties were largely offset by normal field declines, the Partitioned Zone shut-in, the impact of civil unrest in Nigeria and planned turnaround activity. Between 2015 and 2014, production increases from entitlement effects in several locations and project ramp-ups in Bangladesh and other areas were offset by the Partitioned Zone shut-in, normal field declines and the effect of asset sales.

The net liquids component of international oil-equivalent production was 1.22 million barrels per day in 2016, down 2 percent from 2015 and 3 percent from 2014. International net natural gas production of 4.1 billion cubic feet per day in 2016 was up 4 percent from 2015 and 5 percent from 2014.

Refer to the “Selected Operating Data” table, on page FS-12, for a three-year comparison of international production volumes.

U.S. Downstream

Millions of dollars		**2016**		2015		2014
Earnings	**$**	**1,307**	$	3,182	$	2,637

U.S. downstream operations earned $1.31 billion in 2016, compared with $3.18 billion in 2015. The decrease was due to lower margins on refined product sales of $1.45 billion, lower earnings from the 50 percent-owned Chevron Phillips Chemicals Company LLC of $400 million and asset impairments of $110 million. Partially offsetting this decrease were lower operating expenses of $80 million and higher gains on asset sales of $110 million.

U.S. downstream operations earned $3.18 billion in 2015, compared with $2.64 billion in 2014. The increase in earnings was due to higher margins on refined product sales of $1.51 billion, partially offset by the absence of 2014 asset sale gains of $960 million.

Refined product sales of 1.21 million barrels per day in 2016 were down 1 percent, primarily due to lower gas oil sales. Sales volumes of refined products were 1.23 million barrels per day in 2015, an increase of 1 percent from 2014, mainly reflecting higher sales of jet fuel. U.S. branded gasoline sales of 532,000 barrels per day in 2016 increased 2 percent from 2015 and 3 percent from 2014.

Refer to the “Selected Operating Data” table on page FS-12 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

Millions of dollars		**2016**		2015		2014
Earnings*	**$**	**2,128**	$	4,419	$	1,699
*Includes foreign currency effects:	**$**	**(25)**	$	47	$	(112)

International downstream earned $2.13 billion in 2016, compared with $4.42 billion in 2015. The decrease in earnings was primarily due to the absence of a $1.6 billion gain from the sale of the company's interest in Caltex Australia Limited in 2015, partially offset by 2016 asset sales gains of $420 million. Lower margins on refined product sales of $1.14 billion also contributed to the decline. Partially offsetting these decreases were lower operating expenses of $240 million. Foreign currency effects decreased earnings by $25 million in 2016, compared to an increase of $47 million a year earlier.

International downstream earned $4.42 billion in 2015, compared with $1.70 billion in 2014. The increase was primarily due to a $1.6 billion gain from the sale of the company's interest in Caltex Australia in second quarter 2015 and higher margins on refined product sales of $690 million. Foreign currency effects increased earnings by $47 million in 2015, compared to a decrease of $112 million a year earlier.

Total refined product sales of 1.46 million barrels per day in 2016 were down 3 percent from 2015. Excluding the effects of the Caltex Australia Limited divestment, refined product sales were down 1 percent, primarily reflecting lower fuel oil sales. Sales of 1.51 million barrels per day in 2015 were essentially unchanged from 2014.

Refer to the “Selected Operating Data” table, on page FS-12, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

Millions of dollars		**2016**		2015		2014
Net charges*	**$**	**(1,395)**	$	(1,053)	$	(1,988)
*Includes foreign currency effects:	**$**	**(39)**	$	(3)	$	2

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

Net charges in 2016 increased $342 million from 2015, mainly due to higher corporate charges, interest expense and corporate tax items, partially offset by lower environmental reserve additions and lower charges related to reductions in corporate staffs. Net charges in 2015 decreased $935 million from 2014, mainly due to lower corporate tax items and the absence of 2014 charges related to mining assets, partially offset by higher charges related to reductions in corporate staffs.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars		**2016**		2015		2014
Sales and other operating revenues	**$**	**110,215**	$	129,925	$	200,494

Sales and other operating revenues decreased in 2016 primarily due to lower refined product and crude oil prices, partially offset by higher crude oil volumes. The decrease between 2015 and 2014 was primarily due to lower refined product and crude oil prices, partially offset by higher refined product and crude oil volumes

Millions of dollars		**2016**		2015		2014
Income from equity affiliates	**$**	**2,661**	$	4,684	$	7,098

Income from equity affiliates decreased in 2016 from 2015 primarily due to lower upstream-related earnings from Tengizchevroil in Kazakhstan and Petroboscan in Venezuela, and lower downstream-related earnings from CPChem and GS Caltex in South Korea.

Income from equity affiliates decreased in 2015 from 2014 mainly due to lower earnings from Tengizchevroil in Kazakhstan, CPChem, Angola LNG and the effect of the sale of Caltex Australia Limited in second quarter 2015. Partially offsetting these effects were higher earnings from GS Caltex in South Korea and Petropiar in Venezuela.

Refer to Note 16, beginning on page FS-43, for a discussion of Chevron’s investments in affiliated companies.

Millions of dollars		**2016**		2015		2014
Other income	**$**	**1,596**	$	3,868	$	4,378

Other income of $1.6 billion in 2016 included net gains from asset sales of $1.1 billion before-tax. Other income in 2015 and 2014 included net gains from asset sales of $3.2 billion and $3.6 billion before-tax, respectively. Interest income was approximately $145 million in 2016, $119 million in 2015 and $145 million in 2014. Foreign currency effects decreased other income by $186 million in 2016, and increased other income $82 million in 2015 and $277 million in 2014.

Millions of dollars		**2016**		2015		2014
Purchased crude oil and products	**$**	**59,321**	$	69,751	$	119,671

Crude oil and product purchases in 2016 and 2015 decreased from prior year periods by $10.4 billion and $49.9 billion, respectively, primarily due to lower crude oil and refined product prices, partially offset by an increase in crude oil volumes.

Millions of dollars		**2016**		2015		2014
Operating, selling, general and administrative expenses	**$**	**24,952**	$	27,477	$	29,779

Operating, selling, general and administrative expenses decreased $2.5 billion between 2016 and 2015. The decrease included lower employee expenses of $800 million, transportation expenses of $680 million, contract labor expenses of $370 million, materials and supplies expenses of $310 million, and fuel expenses of $310 million.

Operating, selling, general and administrative expenses decreased $2.3 billion between 2015 and 2014. The decrease included lower fuel costs of $920 million. Also contributing to the decrease were lower expenses for construction, repair and maintenance of $300 million, contract labor of $270 million, and research, technical and professional services of $200 million.

Millions of dollars		**2016**		2015		2014
Exploration expense	**$**	**1,033**	$	3,340	$	1,985

Exploration expenses in 2016 decreased from 2015 primarily due to significantly higher 2015 charges for well write-offs largely related to project cancellations, and lower 2016 geological and geophysical expenses.

Exploration expenses in 2015 increased from 2014 primarily due to higher charges for well write-offs largely related to project cancellations.

Millions of dollars		**2016**		2015		2014
Depreciation, depletion and amortization	**$**	**19,457**	$	21,037	$	16,793

Depreciation, depletion and amortization expenses decreased in 2016 from 2015 primarily due to lower impairments of certain oil and gas producing fields of about $3.0 billion in 2016 compared with about $3.5 billion in 2015. Also contributing to the decrease were lower production levels and accretion expenses for certain oil and gas producing fields.

The increase in 2015 from 2014 was primarily due to impairments of oil and gas producing fields of about $3.5 billion in 2015 compared with $900 million in 2014. Also contributing to the increase were higher depreciation rates and higher production levels for certain oil and gas producing fields.

Millions of dollars		**2016**		2015		2014
Taxes other than on income	**$**	**11,668**	$	12,030	$	12,540

Taxes other than on income decreased in 2016 from 2015 primarily due to lower refined product and crude oil prices, and the divestment of the Pakistan fuels business at the end of June 2015. Taxes other than on income decreased in 2015 from 2014 primarily due to lower crude oil and refined product prices.

Millions of dollars		**2016**		2015		2014
Income tax expense (benefit)	**$**	**(1,729)**	$	132	$	11,892

The decline in income tax expense in 2016 of $1.86 billion is consistent with the decline in total income before-tax for the company of $7.00 billion. U.S. losses before tax increased from a loss of $2.88 billion in 2015 to a loss of $4.32 billion in 2016. This $1.44 billion increase in losses was primarily driven by the effect of lower crude oil prices. The increase in losses had a direct impact on the company's U.S. income tax benefit, resulting in an increase of $624 million between year-over-year periods, from a tax benefit of $1.69 billion in 2015 to a tax benefit of $2.32 billion in 2016. International income before tax was reduced between calendar years from $7.72 billion in 2015 to $2.16 billion in 2016. This $5.56 billion decline was

also primarily driven by the effect of lower crude oil prices. This effect drove the $1.24 billion reduction in international income tax expense between year-over-year periods, from $1.83 billion in 2015 to $588 million in 2016. Refer also to the discussion of the effective income tax rate in Note 19 on Page FS-49.

The decline in income tax expense in 2015 of $11.76 billion is consistent with the decline in total income before tax for the company of $26.36 billion. U.S. income before tax was reduced from $6.29 billion in 2014 to a loss of $2.88 billion in 2015. This $9.17 billion reduction was primarily driven by the effect of lower crude oil prices. The lower earnings had a direct impact on the company's U.S. income tax expense, resulting in a reduction of $4.14 billion between year-over-year periods, from a tax expense of $2.45 billion in 2014 to a tax benefit of $1.69 billion in 2015. International income before tax was reduced between calendar years from $24.91 billion in 2014 to $7.72 billion in 2015. This $17.19 billion decline was also primarily driven by the effect of lower crude oil prices and the shut in of production in the Partitioned Zone. These effects drove the $7.62 billion reduction in international income tax expense between year-over-year periods, from $9.44 billion in 2014 to $1.82 billion in 2015. In addition, there was an income tax benefit from the decrease in statutory tax rates in the United Kingdom in 2015. Refer also to the discussion of the effective income tax rate in Note 19 on Page FS-49.

Selected Operating Data[1,2]

	2016	2015	2014
U.S. Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)	**504**	501	456
Net Natural Gas Production (MMCFPD)[3]	**1,120**	1,310	1,250
Net Oil-Equivalent Production (MBOEPD)	**691**	720	664
Sales of Natural Gas (MMCFPD)	**3,317**	3,913	3,995
Sales of Natural Gas Liquids (MBPD)	**30**	26	20
Revenues from Net Production			
Liquids ($/Bbl)	**$ 35.00**	$ 42.70	$ 84.13
Natural Gas ($/MCF)	**$ 1.59**	$ 1.92	$ 3.90
International Upstream			
Net Crude Oil and Natural Gas Liquids Production (MBPD)[4]	**1,215**	1,243	1,253
Net Natural Gas Production (MMCFPD)[3]	**4,132**	3,959	3,917
Net Oil-Equivalent Production (MBOEPD)[4]	**1,903**	1,902	1,907
Sales of Natural Gas (MMCFPD)	**4,491**	4,299	4,304
Sales of Natural Gas Liquids (MBPD)	**24**	24	28
Revenues from Liftings			
Liquids ($/Bbl)	**$ 38.61**	$ 46.52	$ 90.42
Natural Gas ($/MCF)	**$ 4.02**	$ 4.53	$ 5.78
Worldwide Upstream			
Net Oil-Equivalent Production (MBOEPD)[4]			
United States	**691**	720	664
International	**1,903**	1,902	1,907
Total	**2,594**	2,622	2,571
U.S. Downstream			
Gasoline Sales (MBPD)[5]	**631**	621	615
Other Refined Product Sales (MBPD)	**582**	607	595
Total Refined Product Sales (MBPD)	**1,213**	1,228	1,210
Sales of Natural Gas Liquids (MBPD)	**115**	127	121
Refinery Input (MBPD)[6]	**900**	924	871
International Downstream			
Gasoline Sales (MBPD)[5]	**382**	389	403
Other Refined Product Sales (MBPD)	**1,080**	1,118	1,098
Total Refined Product Sales (MBPD)[7]	**1,462**	1,507	1,501
Sales of Natural Gas Liquids (MBPD)	**61**	65	58
Refinery Input (MBPD)[8]	**788**	778	819

[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 crude oil.

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

United States	**54**	66	71
International	**432**	430	452

[4] Includes net production of synthetic oil:

Canada	**50**	47	43
Venezuela affiliate	**28**	29	31

[5] Includes branded and unbranded gasoline.

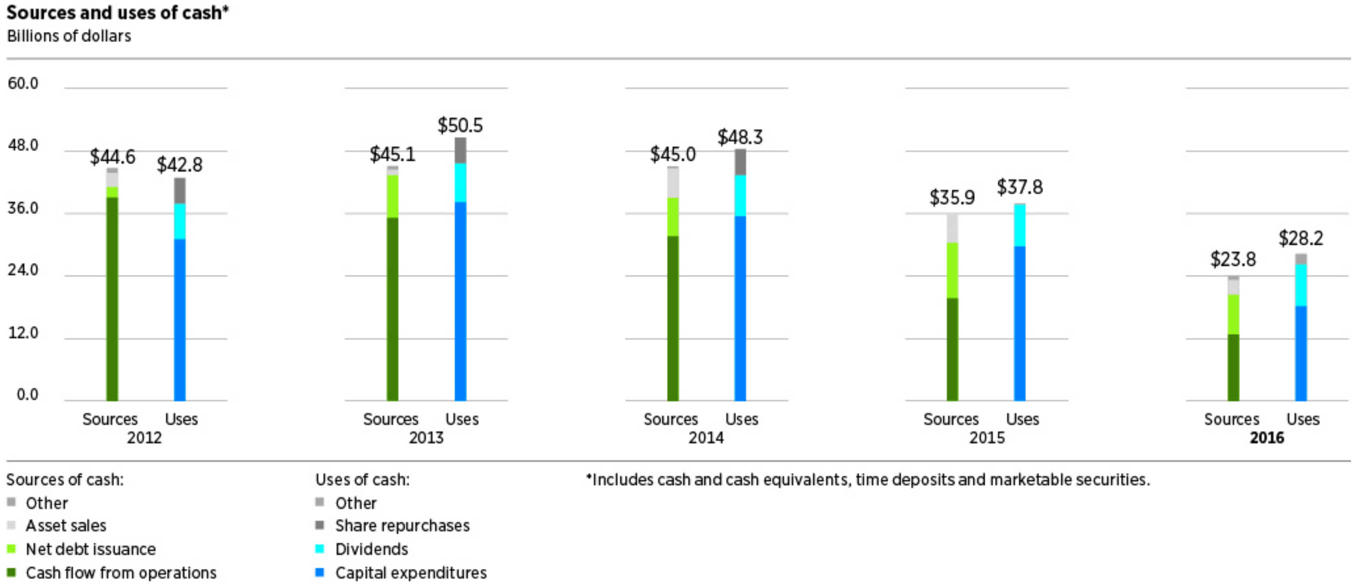
[6] In November 2016, the company sold its interests in the Hawaii Refinery which included operable capacity of 54,000 barrels per day.

[7] Includes sales of affiliates (MBPD):	**377**	420	475

[8] In 2015, the company sold its interests in affiliates in Australia and New Zealand, which included operable refinery capacities of 55,000 and 12,000 barrels per day, respectively.

Liquidity and Capital Resources

Sources and uses of cash



The lower crude oil price environment that began in second-half 2014 and continued through 2016 significantly reduced the company's cash flows from operations. The company responded with reductions in capital and exploratory expenditures, reductions in its cost structure, and increased asset sales. Progress on these actions during 2016 included:

- Reducing capital expenditures to $18.1 billion, a 39 percent decrease compared to 2015,
- Reducing operating and administrative expenses by $2.5 billion, a 9 percent decrease compared to 2015, and
- Realizing net proceeds from asset sales of $2.8 billion during 2016, with additional transactions expected to close in 2017.

The strength of the company's balance sheet enabled it to meet the remaining cash outflows through additional borrowing.

Cash, Cash Equivalents and Marketable Securities Total balances were $7.0 billion and $11.3 billion at December 31, 2016 and 2015, respectively. Cash provided by operating activities in 2016 was $12.8 billion, compared with $19.5 billion in 2015 and $31.5 billion in 2014, reflecting lower crude oil prices. Cash provided by operating activities was net of contributions to employee pension plans of approximately $0.9 billion in 2016 and 2015 and $0.4 billion in 2014. Cash provided by investing activities included proceeds and deposits related to asset sales of $2.8 billion in 2016, $5.7 billion in 2015, and $5.7 billion in 2014.

Restricted cash of $1.4 billion and $1.1 billion at December 31, 2016 and 2015, 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 upstream abandonment activities, tax payments, funds held in escrow for tax-deferred exchanges and refundable deposits related to pending asset sales.

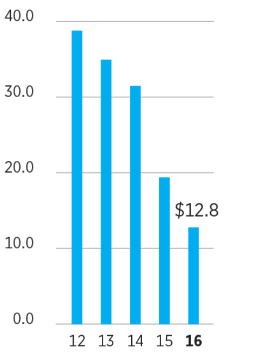
Dividends Dividends paid to common stockholders were $8.0 billion in 2016, $8.0 billion in 2015 and $7.9 billion in 2014. In October 2016, the company increased its quarterly dividend by $0.01 per common share.

Debt and Capital Lease Obligations Total debt and capital lease obligations were $46.1 billion at December 31, 2016, up from $38.5 billion at year-end 2015.

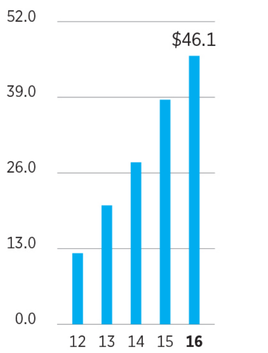
The $7.6 billion increase in total debt and capital lease obligations during 2016 was primarily due to funding the company's capital investment program, which included several large projects in the construction phase. The company completed a bond issuance of $6.8 billion in May 2016. The company's debt 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 $19.8 billion at December 31, 2016, compared with $12.9 billion at year-end 2015. Of these amounts, $9.0 billion and $8.0 billion were reclassified to long-term debt at the end of 2016 and 2015, respectively. At year-end 2016, settlement of these obligations was not expected to require the use of working capital in 2017, 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 August 2018 for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

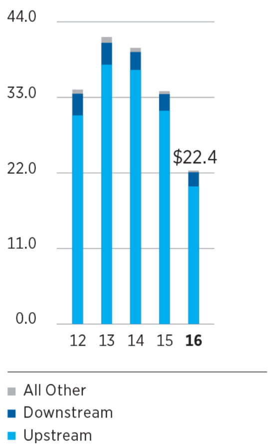
Cash provided by operating activities
Billions of dollars



Total debt at year-end
Billions of dollars

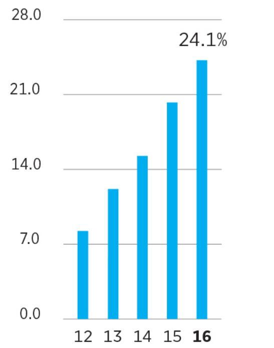


Capital & exploratory expenditures*
Billions of dollars



*Includes equity in affiliates.

Ratio of total debt to total debt-plus-Chevron Corporation stockholders' equity
Percent



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 and Poor's Corporation and Aa2 by Moody's Investors Service. The company's U.S. commercial paper is rated A-1+ by Standard and Poor's and P-1 by Moody's. All of these ratings denote high-quality, investment-grade securities.

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

Committed Credit Facilities Information related to committed credit facilities is included in Note 20, Short-Term Debt, on page FS-52.

Common Stock Repurchase Program In July 2010, the Board of Directors approved an ongoing share repurchase program with no set term or monetary limits. The company did not acquire any shares under the program in 2016 or 2015. From the inception of the program through 2014, the company had purchased 180.9 million shares for $20.0 billion.

Capital and Exploratory Expenditures

Capital and exploratory expenditures by business segment for 2016, 2015 and 2014 are as follows:

			2016			2015			2014
Millions of dollars	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream	**$ 4,713**	**$ 15,403**	**$ 20,116**	$ 7,582	$ 23,535	$ 31,117	$ 8,799	$ 28,316	$ 37,115
Downstream	**1,545**	**527**	**2,072**	1,923	513	2,436	1,649	941	2,590
All Other	**235**	**5**	**240**	418	8	426	584	27	611
Total	**$ 6,493**	**$ 15,935**	**$ 22,428**	$ 9,923	$ 24,056	$ 33,979	$ 11,032	$ 29,284	$ 40,316
Total, Excluding Equity in Affiliates	**$ 5,456**	**$ 13,202**	**$ 18,658**	$ 8,579	$ 22,003	$ 30,582	$ 10,011	$ 26,838	$ 36,849

Total expenditures for 2016 were $22.4 billion, including $3.8 billion for the company's share of equity-affiliate expenditures, which did not require cash outlays by the company. In 2015 and 2014, expenditures were $34.0 billion and $40.3 billion, respectively, including the company's share of affiliates' expenditures of $3.4 billion and $3.5 billion, respectively.

Of the $22.4 billion of expenditures in 2016, 90 percent, or $20.1 billion, related to upstream activities. Approximately 92 percent was expended for upstream operations in both 2015 and 2014. International upstream accounted for 77 percent of the worldwide upstream investment in 2016 and 76 percent in 2015 and 2014.

The company estimates that 2017 capital and exploratory expenditures will be $19.8 billion, including $4.7 billion of spending by affiliates. This planned reduction, compared to 2016 expenditures, reflects current crude oil market conditions, major capital projects nearing completion and the targeting of shorter-cycle projects. Approximately 87 percent of the total, or $17.3 billion, is budgeted for exploration and production activities. Approximately $8.5 billion of planned upstream capital spending relates to base producing assets, including about $2.5 billion for shale and tight resource investments, the majority of which is slated for Permian Basin developments in Texas and New Mexico. Another $7 billion is related to major capital projects already underway, including approximately $2 billion for completion of the Gorgon and Wheatstone LNG projects in Australia and $3 billion of affiliate expenditures associated with the Future Growth and Wellhead Pressure Management Project at the Tengiz Field in Kazakhstan. Global exploration funding accounts for approximately $1 billion, and the remainder is primarily related to early stage projects supporting potential future development opportunities. The company will continue to monitor crude oil market conditions, and will further restrict capital outlays should oil price conditions deteriorate.

Worldwide downstream spending in 2017 is estimated at $2.2 billion, with $1.6 billion for projects in the United States.

Investments in technology companies and other corporate businesses in 2017 are budgeted at $0.3 billion.

Noncontrolling Interests The company had noncontrolling interests of $1.2 billion at December 31, 2016 and December 31, 2015. Distributions to noncontrolling interests totaled $63 million and $128 million in 2016 and 2015, respectively.

Pension Obligations Information related to pension plan contributions is included on page FS-56 in Note 24, Employee Benefit Plans, under the heading "Cash Contributions and Benefit Payments."

Financial Ratios

	At December 31		
	2016	2015	2014
Current Ratio	**0.9**	1.3	1.3
Interest Coverage Ratio	**(2.6)**	9.9	87.2
Debt Ratio	**24.1 %**	20.2 %	15.2 %

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 2016, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $2.9 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 2016 was lower than 2015 and 2014 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 2016 was higher than 2015 and 2014 as the company took on more debt to finance its ongoing investment program.

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: 2017 – $1.5 billion; 2018 – $1.6 billion; 2019 – $1.4 billion; 2020 – $1.1 billion; 2021 – $0.9 billion; 2022 and after – $2.6 billion. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $1.3 billion in 2016, $1.9 billion in 2015 and $3.7 billion in 2014.

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

	Payments Due by Period				
Millions of dollars	Total[1]	2017	2018-2019	2020-2021	After 2021
On Balance Sheet:[2]					
Short-Term Debt[3]	$ 10,840	$ 10,840	$ —	$ —	$ —
Long-Term Debt[3]	35,234	—	19,722	6,108	9,404
Noncancelable Capital Lease Obligations	232	22	41	24	145
Interest	4,344	796	1,237	877	1,434
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	2,481	615	941	533	392
Throughput and Take-or-Pay Agreements[4]	5,455	625	1,327	1,106	2,397
Other Unconditional Purchase Obligations[4]	3,638	902	1,628	933	175

1 Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 24 beginning on page FS-56.

2 Does not include amounts related to the company's income tax liabilities associated with uncertain tax positions. The company is unable to make reasonable estimates of the periods in which 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 $9.0 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 2018–2019 period. The amounts represent only the principal balance.

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	2017	2018-2019	2020-2021	After 2021
Guarantee of nonconsolidated affiliate or joint-venture obligations	$ 1,157	$ 57	$ 326	$ 556	$ 218

The company has two guarantees of equity affiliates totaling $1.16 billion. Of this amount, $749 million is associated with a financing arrangement with an equity affiliate. Over the approximate 5-year remaining term of this guarantee, the maximum amount will be reduced as payments are made by the affiliate. The remaining amount of $408 million is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 11-year remaining term of this 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 either guarantee.

Indemnifications Information related to indemnifications is included on page FS-61 in Note 25, Other Contingencies and Commitments, 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 2016 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 2016.

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. The company's risk management practices and its compliance with policies 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 2016 was not material to the company's results of operations.

The company uses the Monte Carlo simulation method as its Value-at-Risk (VaR) model to estimate the maximum potential loss in fair value, at the 95% confidence level with a one-day holding period, from the effect of adverse changes in market conditions on derivative commodity instruments held or issued. Based on these inputs, the VaR for the company's primary risk exposures in the area of derivative commodity instruments at December 31, 2016 and 2015 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, 2016.

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 2016, 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” on page FS-44, in Note 16, Investments and Advances, 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-45 in Note 18 under the heading “MTBE.”

Ecuador Information related to Ecuador matters is included in Note 18 under the heading “Ecuador,” beginning on page FS-45.

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		**2016**		2015		2014
Balance at January 1	**$**	**1,578**	$	1,683	$	1,456
Net Additions		**260**		365		636
Expenditures		**(371)**		(470)		(409)
Balance at December 31	**$**	**1,467**	$	1,578	$	1,683

The company records asset retirement obligations when there is a legal obligation associated with the retirement of long-lived assets and the liability can be reasonably estimated. These asset retirement obligations include costs related to environmental issues. The liability balance of approximately $14.2 billion for asset retirement obligations at year-end 2016 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 2016 environmental expenditures. Refer to Note 25 on page FS-61 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 26 on page FS-62 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 22, Accounting for Suspended Exploratory Wells, beginning on page FS-54.

Income Taxes Information related to income tax contingencies is included on pages FS-49 through FS-51 in Note 19 and page FS-61 in Note 25 under the heading "Income Taxes."

Other Contingencies Information related to other contingencies is included on page FS-62 in Note 25 to the Consolidated Financial Statements under the heading "Other Contingencies."

Environmental Matters

The company is subject to various international, federal, state and local environmental, health and safety laws, regulations and market-based programs. These laws, regulations and programs continue to evolve and are expected 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. For example, international agreements (e.g., the Paris Agreement and the Kyoto Protocol) and national (e.g., carbon tax, cap-and-trade, or efficiency standards), regional, and state legislation (e.g., California's AB32 and SB32; other low carbon fuel standards) and regulatory measures (e.g., the U.S. Environmental Protection Agency's methane performance standards) that aim to limit or reduce greenhouse gas (GHG) emissions are currently in various stages of implementation. Consideration of GHG issues and the responses to those issues through international agreements and national, regional or state legislation or regulation are integrated into the company's strategy, planning and capital investment reviews, where applicable. They are also factored into the company's long-range supply, demand and energy price forecasts. These forecasts reflect long-range effects from renewable fuel penetration, energy efficiency standards, climate-related policy actions, and demand response to oil and natural gas prices. In addition, legislation and regulations intended to address hydraulic fracturing also continue to evolve at the international, national and state levels. Refer to "Risk Factors" in Part I, Item 1A, on pages 20 through 22 for a discussion of some of the inherent risks of increasingly restrictive environmental and other regulation that could materially impact the company's results of operations or financial condition.

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

Accidental leaks and spills requiring cleanup may occur in the ordinary course of business. 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 2016 at approximately $2.1 billion for its consolidated companies. Included in these expenditures were approximately $0.5 billion of environmental capital expenditures and $1.6 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 2017, total worldwide environmental capital expenditures are estimated at $0.4 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 2016, Chevron's UOP Depreciation, Depletion and Amortization (DD&A) for oil and gas properties was $13.3 billion, and proved developed reserves at the beginning of 2016 were 5.4 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 2016 would have increased by approximately $700 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. 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-69, for the changes in proved reserve estimates for the three years ending December 31, 2016, and to Table VII, “Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves” on page FS-75 for estimates of proved reserve values for each of the three years ended December 31, 2016.

This Oil and Gas Reserves commentary should be read in conjunction with the Properties, Plant and Equipment section of Note 1, beginning on page FS-30, 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 generally 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 17 on page FS-44 and to the section on Properties, Plant and Equipment in Note 1, "Summary of Significant Accounting Policies," beginning on page FS-30.

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. In addition, impairments could occur due to changes in national, state or local environmental regulations or laws, including those designed to stop or impede the development or production of oil and gas. 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. When this occurs, a determination must be made as to whether this loss is other-than-temporary, in which case the investment is impaired. Because of the number of differing assumptions potentially affecting whether an investment is impaired in any period or the amount of the impairment, a sensitivity analysis is not practicable.

The company reported impairments for certain oil and gas properties during 2016 due to reservoir performance and lower crude oil prices. The company reported impairments for certain oil and gas properties during 2015 primarily as a result of downward revisions in the company's longer-term crude oil price outlook. The impairments for the years 2016 and 2015 were primarily in Brazil and the United States. No material individual impairments of PP&E or Investments were recorded for the year 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, or resulted in larger impacts on impaired assets.

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 2016 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 26 on page FS-62 for additional discussions on asset retirement obligations.

Pension and Other Postretirement Benefit Plans Note 24, beginning on page FS-56, includes information on the funded status of the company's pension and other postretirement benefit (OPEB) plans reflected on the Consolidated Balance Sheet; the components of pension and OPEB expense reflected on the Consolidated Statement of Income; and the related underlying assumptions.

The determination of pension plan expense and obligations is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate of return on plan assets and the discount rate applied to pension plan obligations. Critical assumptions in determining expense and obligations for OPEB plans, which provide for certain health care and life insurance benefits for qualifying retired employees and which are not funded, are the discount rate and the assumed health care cost-trend rates. Information related to the company's processes to develop these assumptions is included on page FS-58 in Note 24 under the relevant headings. Actual rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

For 2016, the company used an expected long-term rate of return of 7.25 percent and a discount rate for service costs of 4.4 percent and a discount rate for interest cost of 3.0 percent for U.S. pension plans. The actual return for 2016 was 9.5 percent. For the 10 years ending December 31, 2016, actual asset returns averaged 4.5 percent for the plan. Additionally, with the exception of three years within this 10-year period, actual asset returns for this plan equaled or exceeded 7.25 percent during each year.

Total pension expense for 2016 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 67 percent of companywide pension expense, would have reduced total pension plan expense for 2016 by approximately $86 million. A 1 percent increase in the discount rates for this same plan would have reduced pension expense for 2016 by approximately $297 million.

The aggregate funded status recognized at December 31, 2016, 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, 2016, the company used a discount rate of 3.9 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 62 percent of the companywide pension obligation, would have reduced the plan obligation by approximately $390 million, and would have decreased the plan's underfunded status from approximately $2.0 billion to $1.6 billion.

For the company's OPEB plans, expense for 2016 was $221 million, and the total liability, all unfunded at the end of 2016, was $2.5 billion. For the main U.S. OPEB plan, the company used a discount rate for service cost of 4.9 percent and a discount rate for interest cost of 3.6 percent to measure expense in 2016, and a 4.1 percent discount rate to measure the benefit obligations at December 31, 2016. Discount rate changes, similar to those used in the pension sensitivity analysis, resulted in an immaterial impact on 2016 OPEB expense and OPEB liabilities at the end of 2016. For information on the sensitivity of the health care cost-trend rate, refer to page FS-59 in Note 24 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-57 in Note 24 for a description of the method used to amortize the $5.7 billion of before-tax actuarial losses recorded by the company as of December 31, 2016, and an estimate of the costs to be recognized in expense during 2017. In addition, information related to company contributions is included on page FS-60 in Note 24 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 25 beginning on page FS-61. 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, 2016.

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 5 beginning on page FS-34 for information regarding new accounting standards.

Quarterly Results and Stock Market Data

Unaudited

Millions of dollars, except per-share amounts	2016 4th Q	2016 3rd Q	2016 2nd Q	2016 1st Q	2015 4th Q	2015 3rd Q	2015 2nd Q	2015 1st Q
Revenues and Other Income								
Sales and other operating revenues[1]	**$ 30,142**	**$29,159**	**$ 27,844**	**$ 23,070**	$28,014	$ 32,767	$ 36,829	$ 32,315
Income from equity affiliates	**778**	**555**	**752**	**576**	919	1,195	1,169	1,401
Other income	**577**	**426**	**686**	**(93)**	314	353	2,359	842
Total Revenues and Other Income	**31,497**	**30,140**	**29,282**	**23,553**	29,247	34,315	40,357	34,558
Costs and Other Deductions								
Purchased crude oil and products	**16,976**	**15,842**	**15,278**	**11,225**	14,570	17,447	20,541	17,193
Operating expenses	**5,144**	**4,666**	**5,054**	**5,404**	5,970	5,592	6,077	5,395
Selling, general and administrative expenses	**1,544**	**1,109**	**1,033**	**998**	1,303	1,026	1,170	944
Exploration expenses	**191**	**258**	**214**	**370**	1,358	315	1,075	592
Depreciation, depletion and amortization	**4,203**	**4,130**	**6,721**	**4,403**	5,400	4,268	6,958	4,411
Taxes other than on income[1]	**2,869**	**2,962**	**2,973**	**2,864**	2,856	2,883	3,173	3,118
Interest and debt expense	**58**	**64**	**79**	**—**	—	—	—	—
Total Costs and Other Deductions	**30,985**	**29,031**	**31,352**	**25,264**	31,457	31,531	38,994	31,653
Income (Loss) Before Income Tax Expense	**512**	**1,109**	**(2,070)**	**(1,711)**	(2,210)	2,784	1,363	2,905
Income Tax Expense (Benefit)	**74**	**(192)**	**(607)**	**(1,004)**	(1,655)	727	755	305
Net Income (Loss)	**$ 438**	**$ 1,301**	**$ (1,463)**	**$ (707)**	$ (555)	$ 2,057	$ 608	$ 2,600
Less: Net income attributable to noncontrolling interests	**23**	**18**	**7**	**18**	33	20	37	33
Net Income (Loss) Attributable to Chevron Corporation	**$ 415**	**$ 1,283**	**$ (1,470)**	**$ (725)**	$ (588)	$ 2,037	$ 571	$ 2,567
Per Share of Common Stock								
Net Income (Loss) Attributable to Chevron Corporation								
– Basic	**$ 0.22**	**$ 0.68**	**$ (0.78)**	**$ (0.39)**	$ (0.31)	$ 1.09	$ 0.30	$ 1.38
– Diluted	**$ 0.22**	**$ 0.68**	**$ (0.78)**	**$ (0.39)**	$ (0.31)	$ 1.09	$ 0.30	$ 1.37
Dividends	**$ 1.08**	**$ 1.07**	**$ 1.07**	**$ 1.07**	$ 1.07	$ 1.07	$ 1.07	$ 1.07
Common Stock Price Range – High[2]	**$ 119.00**	**$107.58**	**$ 105.00**	**$ 97.91**	$ 98.64	$ 96.67	$ 112.20	$ 113.00
– Low[2]	**$ 99.61**	**$97.53**	**$ 92.43**	**$ 75.33**	$ 77.31	$ 69.58	$ 96.22	$ 98.88
[1] Includes excise, value-added and similar taxes:	**$ 1,697**	**$ 1,772**	**$ 1,784**	**$ 1,652**	$ 1,717	$ 1,800	$ 1,965	$ 1,877

[2] Intraday price.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 15, 2017, stockholders of record numbered approximately 138,000. 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 Corporation 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.

The company's management has evaluated, with the participation of the Chief Executive Officer and Chief Financial Officer, the effectiveness of the company's disclosure controls and procedures (as defined in the Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2016. Based on that evaluation, management concluded that the company's disclosure controls are effective in ensuring that information required to be recorded, processed, summarized and reported, are done within the time periods specified in the U.S. Securities and Exchange Commission's rules and forms.

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 defined in the Exchange Act Rules 13a-15(f) and 15d-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, 2016.

The effectiveness of the company’s internal control over financial reporting as of December 31, 2016, 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/ JEANETTE L. OURADA
John S. Watson	Patricia E. Yarrington	Jeanette L. Ourada
Chairman of the Board	Vice President	Vice President
and Chief Executive Officer	and Chief Financial Officer	and Comptroller

February 23, 2017

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 sheets 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, 2016, and December 31, 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, 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, 2016, 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.

As discussed in Note 19 to the consolidated financial statements, the Company changed the manner in which it classifies deferred income taxes in the balance sheet.

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/ PRICEWATERHOUSECOOPERS LLP

San Francisco, California

February 23, 2017

Consolidated Statement of Income

Millions of dollars, except per-share amounts

		Year ended December 31				
		2016		2015		2014
Revenues and Other Income						
Sales and other operating revenues*	**$**	**110,215**	$	129,925	$	200,494
Income from equity affiliates		**2,661**		4,684		7,098
Other income		**1,596**		3,868		4,378
Total Revenues and Other Income		**114,472**		138,477		211,970
Costs and Other Deductions						
Purchased crude oil and products		**59,321**		69,751		119,671
Operating expenses		**20,268**		23,034		25,285
Selling, general and administrative expenses		**4,684**		4,443		4,494
Exploration expenses		**1,033**		3,340		1,985
Depreciation, depletion and amortization		**19,457**		21,037		16,793
Taxes other than on income*		**11,668**		12,030		12,540
Interest and debt expense		**201**		—		—
Total Costs and Other Deductions		**116,632**		133,635		180,768
Income (Loss) Before Income Tax Expense		**(2,160)**		4,842		31,202
Income Tax Expense (Benefit)		**(1,729)**		132		11,892
Net Income (Loss)		**(431)**		4,710		19,310
Less: Net income attributable to noncontrolling interests		**66**		123		69
Net Income (Loss) Attributable to Chevron Corporation	**$**	**(497)**	$	4,587	$	19,241
Per Share of Common Stock						
Net Income (Loss) Attributable to Chevron Corporation						
- Basic	**$**	**(0.27)**	$	2.46	$	10.21
- Diluted	**$**	**(0.27)**	$	2.45	$	10.14
* Includes excise, value-added and similar taxes.	**$**	**6,905**	$	7,359	$	8,186

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2016	2015	2014
Net Income (Loss)	**$ (431)**	$ 4,710	$ 19,310
Currency translation adjustment			
Unrealized net change arising during period	**(22)**	(44)	(73)
Unrealized holding gain (loss) on securities			
Net gain (loss) arising during period	**27**	(21)	(2)
Derivatives			
Net derivatives loss on hedge transactions	**—**	—	(66)
Reclassification to net income of net realized gain	**—**	—	(17)
Income taxes on derivatives transactions	**—**	—	29
Total	**—**	—	(54)
Defined benefit plans			
Actuarial gain (loss)			
Amortization to net income of net actuarial loss and settlements	**918**	794	757
Actuarial gain (loss) arising during period	**(315)**	109	(2,730)
Prior service credits (cost)			
Amortization to net income of net prior service costs and curtailments	**19**	30	26
Prior service credits (costs) arising during period	**345**	6	(6)
Defined benefit plans sponsored by equity affiliates - (cost) benefit	**(19)**	30	(99)
Income (taxes) benefit on defined benefit plans	**(505)**	(336)	901
Total	**443**	633	(1,151)
Other Comprehensive Gain (Loss), Net of Tax	**448**	568	(1,280)
Comprehensive Income (Loss)	**17**	5,278	18,030
Comprehensive income attributable to noncontrolling interests	**(66)**	(123)	(69)
Comprehensive Income (Loss) Attributable to Chevron Corporation	**$ (49)**	$ 5,155	$ 17,961

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

Millions of dollars, except per-share amount

	At December 31	
	2016	2015
Assets		
Cash and cash equivalents	**$ 6,988**	$ 11,022
Marketable securities	**13**	310
Accounts and notes receivable (less allowance: 2016 - $373; 2015 - $313)	**14,092**	12,860
Inventories:		
Crude oil and petroleum products	**2,720**	3,535
Chemicals	**455**	490
Materials, supplies and other	**2,244**	2,309
Total inventories	**5,419**	6,334
Prepaid expenses and other current assets[1]	**3,107**	3,904
Total Current Assets	**29,619**	34,430
Long-term receivables, net	**2,485**	2,412
Investments and advances	**30,250**	27,110
Properties, plant and equipment, at cost	**336,077**	340,277
Less: Accumulated depreciation, depletion and amortization	**153,891**	151,881
Properties, plant and equipment, net	**182,186**	188,396
Deferred charges and other assets[1,2]	**6,838**	6,155
Goodwill	**4,581**	4,588
Assets held for sale	**4,119**	1,449
Total Assets	**$ 260,078**	$ 264,540
Liabilities and Equity		
Short-term debt[2] (net of unamortized discount and debt issuance costs: $3 in 2016, $1 in 2015)	**$ 10,840**	$ 4,927
Accounts payable	**13,986**	13,516
Accrued liabilities	**4,882**	4,833
Federal and other taxes on income[1]	**1,050**	1,073
Other taxes payable	**1,027**	1,118
Total Current Liabilities	**31,785**	25,467
Long-term debt[2] (net of unamortized discount and debt issuance costs: $41 in 2016, $42 in 2015)	**35,193**	33,542
Capital lease obligations	**93**	80
Deferred credits and other noncurrent obligations	**21,553**	23,465
Noncurrent deferred income taxes[1]	**17,516**	20,165
Noncurrent employee benefit plans	**7,216**	7,935
Total Liabilities[3]	**$ 113,356**	$ 110,654
Preferred stock (authorized 100,000,000 shares; $1.00 par value; none issued)	**—**	—
Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2016 and 2015)	**1,832**	1,832
Capital in excess of par value	**16,595**	16,330
Retained earnings	**173,046**	181,578
Accumulated other comprehensive loss	**(3,843)**	(4,291)
Deferred compensation and benefit plan trust	**(240)**	(240)
Treasury stock, at cost (2016 - 551,170,158 shares; 2015 - 559,862,580 shares)	**(41,834)**	(42,493)
Total Chevron Corporation Stockholders' Equity	**145,556**	152,716
Noncontrolling interests	**1,166**	1,170
Total Equity	**146,722**	153,886
Total Liabilities and Equity	**$ 260,078**	$ 264,540

See accompanying Notes to the Consolidated Financial Statements.

[1] 2015 adjusted to conform to ASU 2015-17. Refer to Note 19, "Income Taxes" beginning on page FS-49.

[2] 2015 adjusted to conform to ASU 2015-03. Refer to Note 5, "New Accounting Standards" beginning on page FS-34.

[3] Refer to Note 25, "Other Contingencies and Commitments" beginning on page FS-61.

Consolidated Statement of Cash Flows

Millions of dollars

	Year ended December 31		
	2016	2015	2014
Operating Activities			
Net Income (Loss)	**$ (431)**	$ 4,710	$ 19,310
Adjustments			
Depreciation, depletion and amortization	**19,457**	21,037	16,793
Dry hole expense	**489**	2,309	875
Distributions less than income from equity affiliates	**(1,227)**	(760)	(2,202)
Net before-tax gains on asset retirements and sales	**(1,149)**	(3,215)	(3,540)
Net foreign currency effects	**186**	(82)	(277)
Deferred income tax provision	**(3,835)**	(1,861)	1,572
Net increase in operating working capital	**(550)**	(1,979)	(540)
(Increase) in long-term receivables	**(131)**	(59)	(9)
Decrease in other deferred charges	**235**	25	263
Cash contributions to employee pension plans	**(870)**	(868)	(392)
Other	**672**	199	(378)
Net Cash Provided by Operating Activities	**12,846**	19,456	31,475
Investing Activities			
Capital expenditures	**(18,109)**	(29,504)	(35,407)
Proceeds and deposits related to asset sales	**2,777**	5,739	5,729
Net maturities of time deposits	**—**	8	—
Net sales (purchases) of marketable securities	**297**	122	(148)
Net (borrowing) repayment of loans by equity affiliates	**(2,034)**	(217)	140
Net sales (purchases) of other short-term investments	**217**	44	(207)
Net Cash Used for Investing Activities	**(16,852)**	(23,808)	(29,893)
Financing Activities			
Net borrowings (repayments) of short-term obligations	**2,130**	(335)	3,431
Proceeds from issuances of long-term debt	**6,924**	11,091	4,000
Repayments of long-term debt and other financing obligations	**(1,584)**	(32)	(43)
Cash dividends - common stock	**(8,032)**	(7,992)	(7,928)
Distributions to noncontrolling interests	**(63)**	(128)	(47)
Net sales of treasury shares	**650**	211	(4,412)
Net Cash Provided by (Used for) Financing Activities	**25**	2,815	(4,999)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(53)**	(226)	(43)
Net Change in Cash and Cash Equivalents	**(4,034)**	(1,763)	(3,460)
Cash and Cash Equivalents at January 1	**11,022**	12,785	16,245
Cash and Cash Equivalents at December 31	**$ 6,988**	$ 11,022	$ 12,785

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	2016		2015		2014	
	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		**$ 16,330**		$ 16,041		$ 15,713
Treasury stock transactions		**265**		289		328
Balance at December 31		**$ 16,595**		$ 16,330		$ 16,041
Retained Earnings						
Balance at January 1		**$ 181,578**		$ 184,987		$ 173,677
Net income (loss) attributable to Chevron Corporation		**(497)**		4,587		19,241
Cash dividends on common stock		**(8,032)**		(7,992)		(7,928)
Stock dividends		**(3)**		(3)		(3)
Tax (charge) benefit from dividends paid on unallocated ESOP shares and other		**—**		(1)		—
Balance at December 31		**$ 173,046**		$ 181,578		$ 184,987
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		**$ (140)**		$ (96)		$ (23)
Change during year		**(22)**		(44)		(73)
Balance at December 31		**$ (162)**		$ (140)		$ (96)
Unrealized net holding (loss) gain on securities						
Balance at January 1		**$ (29)**		$ (8)		$ (6)
Change during year		**27**		(21)		(2)
Balance at December 31		**$ (2)**		$ (29)		$ (8)
Net derivatives (loss) gain on hedge transactions						
Balance at January 1		**$ (2)**		$ (2)		$ 52
Change during year		**—**		—		(54)
Balance at December 31		**$ (2)**		$ (2)		$ (2)
Pension and other postretirement benefit plans						
Balance at January 1		**$ (4,120)**		$ (4,753)		$ (3,602)
Change during year		**443**		633		(1,151)
Balance at December 31		**$ (3,677)**		$ (4,120)		$ (4,753)
Balance at December 31		**$ (3,843)**		$ (4,291)		$ (4,859)
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	$ (240)
Treasury Stock at Cost						
Balance at January 1	**559,863**	**$ (42,493)**	563,028	$ (42,733)	529,074	$ (38,290)
Purchases	**20**	**(2)**	15	(2)	41,592	(5,006)
Issuances - mainly employee benefit plans	**(8,713)**	**661**	(3,180)	242	(7,638)	563
Balance at December 31	**551,170**	**$ (41,834)**	559,863	$ (42,493)	563,028	$ (42,733)
Total Chevron Corporation Stockholders' Equity at December 31		**$ 145,556**		$ 152,716		$ 155,028
Noncontrolling Interests		**$ 1,166**		$ 1,170		$ 1,163
Total Equity		**$ 146,722**		$ 153,886		$ 156,191

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.

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 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs other than quoted prices included within Level 1 that are directly or indirectly observable for the asset or liability. Level 3 inputs are inputs that are not observable in the market.

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 22, beginning on page FS-54, for additional discussion of accounting for suspended exploratory well costs.

Long-lived assets to be held and used, including proved crude oil and natural gas properties, are assessed for possible impairment by comparing their carrying values with their associated undiscounted, future net 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 cash flows. For proved crude oil and natural gas properties, the company performs impairment reviews on a country, concession, PSC, 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 10, beginning on page FS-37, 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 26, on page FS-62, 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.

Effective in the quarter ended December 31, 2016, the company has elected to move the annual review of the goodwill balance from the third to fourth quarter to better align with the preparation and review of the company's business plan, which is used in the test. The change does not delay, accelerate or avoid an impairment charge.

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 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 26, on page FS-62, 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-25. 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 in the first, second and third anniversaries of the date of grant. Beginning in 2017, stock options and stock appreciation rights granted under the company's Long-Term Incentive Plan have graded vesting by which one third of each award vests annually on each January 31 on or after the first anniversary of the grant date. Standard restricted stock units have cliff vesting by which the total award will vest on January 31 on or after the fifth anniversary of the grant date. The company amortizes these 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, 2016, are reflected in the table below.

	Year Ended December 31, 2016[1]				
	Currency Translation Adjustment	Unrealized Holding Gains (Losses) on Securities	Derivatives	Defined Benefit Plans	Total
Balance at January 1	$ (140)	$ (29)	$ (2)	$ (4,120)	$ (4,291)
Components of Other Comprehensive Income (Loss):					
Before Reclassifications	(22)	27	—	(161)	(156)
Reclassifications[2]	—	—	—	604	604
Net Other Comprehensive Income (Loss)	(22)	27	—	443	448
Balance at December 31	$ (162)	$ (2)	$ (2)	$ (3,677)	$ (3,843)

[1] All amounts are net of tax.

[2] Refer to Note 24 beginning on page FS-56, for reclassified components totaling $937 that are included in employee benefit costs for the year ending December 31, 2016. Related income taxes for the same period, totaling $333, 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 (Loss) Attributable to Chevron Corporation."

Activity for the equity attributable to noncontrolling interests for 2016, 2015 and 2014 is as follows:

	2016	2015	2014
Balance at January 1	**$ 1,170**	$ 1,163	$ 1,314
Net income	**66**	123	69
Distributions to noncontrolling interests	**(63)**	(128)	(47)
Other changes, net	**(7)**	12	(173)
Balance at December 31	**$ 1,166**	$ 1,170	$ 1,163

Note 4

Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31		
	2016	2015	2014
Net increase in operating working capital was composed of the following:			
(Increase) decrease in accounts and notes receivable	**$ (2,121)**	$ 3,631	$ 4,491
Decrease (increase) in inventories	**603**	85	(146)
Decrease (increase) in prepaid expenses and other current assets	**439**	713	(407)
Increase (decrease) in accounts payable and accrued liabilities	**533**	(5,769)	(3,737)
Decrease in income and other taxes payable	**(4)**	(639)	(741)
Net increase in operating working capital	**$ (550)**	$ (1,979)	$ (540)
Net cash provided by operating activities includes the following cash payments for interest on debt and for income taxes:			
Interest on debt (net of capitalized interest)	**$ 158**	$ —	$ —
Income taxes	**1,935**	4,645	10,562
Net sales (purchases) of marketable securities consisted of the following gross amounts:			
Marketable securities purchased	**$ (9)**	$ (6)	$ (162)
Marketable securities sold	**306**	128	14
Net sales (purchases) of marketable securities	**$ 297**	$ 122	$ (148)
Net maturities of time deposits consisted of the following gross amounts:			
Investments in time deposits	**$ —**	$ —	$ (317)
Maturities of time deposits	**—**	8	317
Net maturities of time deposits	**$ —**	$ 8	$ —
Net (borrowing) repayment of loans by equity affiliates:			
Borrowing of loans by equity affiliates	**$ (2,341)**	$ (223)	$ (176)
Repayment of loans by equity affiliates	**307**	6	316
Net (borrowing) repayment of loans by equity affiliates	**$ (2,034)**	$ (217)	$ 140
Net sales (purchases) of other short-term investments:			
Purchases of other short-term investments	**$ (1)**	$ (75)	$ (223)
Sales of other short-term investments	**218**	119	16
Net sales (purchases) of other short-term investments	**$ 217**	$ 44	$ (207)
Net borrowings (repayments) of short-term obligations consisted of the following gross and net amounts:			
Proceeds from issuances of short-term obligations	**$ 14,778**	$ 13,805	$ 9,070
Repayments of short-term obligations	**(12,558)**	(16,379)	(4,612)
Net borrowings (repayments) of short-term obligations with three months or less maturity	**(90)**	2,239	(1,027)
Net borrowings (repayments) of short-term obligations	**$ 2,130**	$ (335)	$ 3,431

A loan to Tengizchevroil LLP for the development of the Future Growth and Wellhead Pressure Management Project represents the majority of "Net (borrowing) repayment of loans by equity affiliates."

The “Net sales of treasury shares” represents the cost of common shares acquired less the cost of shares issued for share-based compensation plans. Purchases totaled $2, $2 and $5,006 in 2016, 2015 and 2014, respectively. No purchases were made under the company's share repurchase program in 2016 or 2015. In 2014, the company purchased 41.5 million common shares for $5,000 under its share repurchase program.

In 2016, 2015 and 2014, "Net sales (purchases) of other short-term investments" generally consisted of restricted cash associated with upstream abandonment activities, tax payments and certain pension fund 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. "Depreciation, depletion and amortization" and "Deferred income tax provision" collectively include approximately $2,800 in non-cash reductions to properties, plant and equipment recorded in 2016 relating to impairments and other non-cash charges due to reservoir performance and lower crude prices.

Refer also to Note 26, on page FS-62, 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, 2016.

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		
	2016	2015	2014
Additions to properties, plant and equipment *	**$ 17,742**	$ 28,213	$ 34,393
Additions to investments	**55**	555	526
Current-year dry hole expenditures	**313**	736	504
Payments for other liabilities and assets, net	**(1)**	—	(16)
Capital expenditures	**18,109**	29,504	35,407
Expensed exploration expenditures	**544**	1,031	1,110
Assets acquired through capital lease obligations and other financing obligations	**5**	47	332
Capital and exploratory expenditures, excluding equity affiliates	**18,658**	30,582	36,849
Company's share of expenditures by equity affiliates	**3,770**	3,397	3,467
Capital and exploratory expenditures, including equity affiliates	**$ 22,428**	$ 33,979	$ 40,316

* Excludes noncash additions of $56 in 2016, $1,362 in 2015 and $2,310 in 2014.

Note 5
New Accounting Standards

Revenue Recognition (Topic 606): Revenue from Contracts with Customers In July 2015, the FASB approved a one-year deferral of the effective date of ASU 2014-09, which becomes effective for the company January 1, 2018. The standard provides a single comprehensive revenue recognition model for contracts with customers, eliminates most industry-specific revenue recognition guidance, and expands disclosure requirements. The company has elected to adopt the standard using the modified retrospective transition method. "Sales and Other Operating Revenues" on the Consolidated Statement of Income includes excise, value-added and similar taxes on sales transactions. Upon adoption of the standard, revenue will exclude sales-based taxes collected on behalf of third parties, which will have no impact to earnings. The company's implementation efforts are focused on accounting policy and disclosure updates and system enhancements necessary to meet the standard's requirements. The company continues to evaluate the effect of the standard on its consolidated financial statements.

Interest - Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs Effective January 1, 2016, Chevron adopted ASU 2015-03 on a retrospective basis. The standard requires that debt issuance costs related to a recognized liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability. The effects of retrospective adoption on the December 31, 2015, Consolidated Balance Sheet were reductions of $43 in "Deferred charges and other assets," $1 in "Short-term debt" and $42 in "Long-term debt."

Leases (Topic 842) In February 2016, the FASB issued ASU 2016-02 which becomes effective for the company January 1, 2019. The standard requires that lessees present right-of-use assets and lease liabilities on the balance sheet. The company is evaluating the effect of the standard on the company's consolidated financial statements.

Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting In March 2016, the FASB issued ASU 2016-09 which the company elected to early-adopt retrospective to January 1, 2016. The standard requires that all excess tax benefits and tax deficiencies are recognized as income tax expense or benefit in the income statement, regardless of whether the benefit reduces taxes payable in the current period. In addition, excess tax benefits are to be classified along with other income tax cash flows as an operating activity in the statement of cash flows. The effect of the early adoption is not material to the company's consolidated financial statements.

Financial Instruments - Credit Losses (Topic 326) In June 2016, the FASB issued ASU 2016-13, which becomes effective for the company beginning January 1, 2020. The standard requires companies to use forward-looking information to calculate credit loss estimates. The company is evaluating the effect of the standard on the company's consolidated financial statements.

Intangibles - Goodwill and Other (Topic 350) In January 2017, the FASB issued ASU 2017-04. The standard simplifies the accounting for goodwill impairment, and the company has chosen to early adopt beginning January 1, 2017. Early adoption has no effect on the company's consolidated financial statements.

Note 6

Lease Commitments

Certain noncancellable 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	
	2016	2015
Upstream	**$ 676**	$ 800
Downstream	**99**	98
All Other	**—**	—
Total	**775**	898
Less: Accumulated amortization	**383**	448
Net capitalized leased assets	**$ 392**	$ 450

Rental expenses incurred for operating leases during 2016, 2015 and 2014 were as follows:

	Year ended December 31		
	2016	2015	2014
Minimum rentals	**$ 943**	$ 1,041	$ 1,080
Contingent rentals	**2**	2	1
Total	**945**	1,043	1,081
Less: Sublease rental income	**7**	9	14
Net rental expense	**$ 938**	$ 1,034	$ 1,067

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, 2016, 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 2017	$ 615	$ 22
2018	554	20
2019	387	21
2020	298	12
2021	235	12
Thereafter	392	145
Total	$ 2,481	$ 232
Less: Amounts representing interest and executory costs		$ (125)
Net present values		107

Less: Capital lease obligations included in short-term debt		(14)
Long-term capital lease obligations	$	93

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		
	2016	2015	2014
Sales and other operating revenues	**$ 83,715**	$ 97,766	$ 157,198
Total costs and other deductions	**87,429**	101,565	153,139
Net income (loss) attributable to CUSA	**(1,177)**	(1,054)	3,849

	2016	2015*
Current assets	**$ 11,266**	$ 9,096
Other assets	**55,722**	59,171
Current liabilities	**16,660**	13,664
Other liabilities	**21,701**	28,465
Total CUSA net equity	**$ 28,627**	$ 26,138
Memo: Total debt	**$ 9,418**	$ 14,462

* 2015 adjusted to conform to ASU 2015-17.

Note 8

Summarized Financial Data – Tengizchevroil LLP

Chevron has a 50 percent equity ownership interest in Tengizchevroil LLP (TCO). Refer to Note 16, beginning on page FS-43, for a discussion of TCO operations. Summarized financial information for 100 percent of TCO is presented in the table below:

	Year ended December 31		
	2016	2015	2014
Sales and other operating revenues	**$ 10,460**	$ 12,811	$ 22,813
Costs and other deductions	**6,822**	7,257	10,275
Net income attributable to TCO	**2,563**	3,897	8,772

	At December 31	
	2016	2015
Current assets	**$ 7,001**	$ 2,098
Other assets	**20,476**	17,094
Current liabilities	**2,841**	1,063
Other liabilities	**6,210**	2,266
Total TCO net equity	**$ 18,426**	$ 15,863

Note 9

Summarized Financial Data – Chevron Phillips Chemical Company LLC

Chevron has a 50 percent equity ownership interest in Chevron Phillips Chemical Company LLC (CPChem). Refer to Note 16, beginning on page FS-43, for a discussion of CPChem operations. Summarized financial information for 100 percent of CPChem is presented in the table below:

	Year ended December 31		
	2016	2015	2014
Sales and other operating revenues	**$ 8,455**	$ 9,248	$ 13,416
Costs and other deductions	**7,017**	7,136	10,776
Net income attributable to CPChem	**1,687**	2,651	3,288

	At December 31	
	2016	2015
Current assets	**$ 2,695**	$ 2,291
Other assets	**12,770**	11,306
Current liabilities	**1,418**	1,319
Other liabilities	**2,569**	2,013
Total CPChem net equity	**$ 11,478**	$ 10,265

Note 10

Fair Value Measurements

The tables below and 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, 2016, and December 31, 2015.

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, 2016.

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 during 2016 primarily due to reservoir performance and lower crude oil prices. The company reported impairments for certain oil and gas properties in 2015 primarily as a result of downward revisions in the company's longer-term crude oil price outlook. The impairments in 2016 and 2015 were primarily in Brazil and the United States.

Investments and Advances The company did not have any material investments and advances measured at fair value on a nonrecurring basis to report in 2016 or 2015.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2016				At December 31, 2015			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Marketable securities	**$ 13**	**$ 13**	**$ —**	**$ —**	$ 310	$ 310	$ —	$ —
Derivatives	**32**	**15**	**17**	**—**	205	189	16	—
Total assets at fair value	**$ 45**	**$ 28**	**$ 17**	**$ —**	$ 515	$ 499	$ 16	$ —
Derivatives	**109**	**78**	**31**	**—**	53	47	6	—
Total liabilities at fair value	**$ 109**	**$ 78**	**$ 31**	**$ —**	$ 53	$ 47	$ 6	$ —

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 2016	Total	Level 1	Level 2	Level 3	Year 2015
Properties, plant and equipment, net (held and used)	**$ 582**	**$ —**	**$ 15**	**$ 567**	**$ 2,507**	$ 3,051	$ —	$ 239	$ 2,812	$ 3,222
Properties, plant and equipment, net (held for sale)	**891**	**—**	**888**	**3**	**679**	937	—	937	—	844
Investments and advances	**26**	**—**	**20**	**6**	**234**	75	—	75	—	28
Total nonrecurring assets at fair value	**$ 1,499**	**$ —**	**$ 923**	**$ 576**	**$ 3,420**	$ 4,063	$ —	$ 1,251	$ 2,812	$ 4,094

Assets and Liabilities Not Required to Be Measured at Fair Value The company holds cash equivalents and 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 $6,988 and

$11,022 at December 31, 2016, and December 31, 2015, respectively. The fair values of cash and cash equivalents are classified as Level 1 and reflect the cash that would have been received if the instruments were settled at December 31, 2016.

"Cash and cash equivalents" do not include investments with a carrying/fair value of $1,426 and $1,100 at December 31, 2016, and December 31, 2015, respectively. At December 31, 2016, these investments are classified as Level 1 and include restricted funds related to certain upstream abandonment activities, tax payments, funds held in escrow for tax-deferred exchanges and refundable deposits related to pending asset sales, which are reported in "Deferred charges and other assets" on the Consolidated Balance Sheet. Long-term debt of $26,193 and $25,542 at December 31, 2016, and December 31, 2015, had estimated fair values of $26,627 and $25,884, respectively. Long-term debt primarily includes corporate issued bonds. The fair value of corporate bonds is $25,860 and classified as Level 1. The fair value of other long-term debt is $767 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, 2016 and 2015, were not material.

Note 11

Financial and Derivative Instruments

Derivative Commodity Instruments 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, 2016, December 31, 2015, and December 31, 2014, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are below:

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

		At December 31	
Type of Contract	Balance Sheet Classification	**2016**	2015
Commodity	Accounts and notes receivable, net	**$ 30**	$ 200
Commodity	Long-term receivables, net	**2**	5
Total assets at fair value		**$ 32**	$ 205
Commodity	Accounts payable	**$ 99**	$ 51
Commodity	Deferred credits and other noncurrent obligations	**10**	2
Total liabilities at fair value		**$ 109**	$ 53

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	**2016**	2015	2014
Commodity	Sales and other operating revenues	**$ (269)**	$ 277	$ 553
Commodity	Purchased crude oil and products	**(31)**	30	(17)
Commodity	Other income	**—**	(3)	(32)
		$ (300)	$ 304	$ 504

The table on the following page represents gross and net derivative assets and liabilities subject to netting agreements on the Consolidated Balance Sheet at December 31, 2016 and December 31, 2015.

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

At December 31, 2016		Gross Amount Recognized		Gross Amounts Offset		Net Amounts Presented		Gross Amounts Not Offset		Net Amount
Derivative Assets	$	1,052	$	1,020	$	32	$	—	$	32
Derivative Liabilities	$	1,129	$	1,020	$	109	$	—	$	109
At December 31, 2015										
Derivative Assets	$	2,459	$	2,254	$	205	$	—	$	205
Derivative Liabilities	$	2,307	$	2,254	$	53	$	—	$	53

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, 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 12
Assets Held for Sale

At December 31, 2016, the company classified $4,119 of net properties, plant and equipment as “Assets held for sale” on the Consolidated Balance Sheet. These assets are associated with upstream operations that are anticipated to be sold in the next 12 months. The revenues and earnings contributions of these assets in 2016 were not material.

Note 13
Equity

Retained earnings at December 31, 2016 and 2015, included approximately $16,479 and $15,010, respectively, for the company’s share of undistributed earnings of equity affiliates.

At December 31, 2016, about 87 million shares of Chevron’s common stock remained available for issuance from the 260 million shares that were reserved for issuance under the Chevron Long-Term Incentive Plan. In addition, 859,746 shares remain available for issuance from the 1,600,000 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 14
Earnings Per Share

Basic earnings per share (EPS) is based upon “Net Income (Loss) 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 23, “Stock Options and Other Share-Based Compensation,” beginning on page FS-55). The table on the following page sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2016	2015	2014
Basic EPS Calculation			
Earnings available to common stockholders - Basic[1]	**$ (497)**	$ 4,587	$ 19,241
Weighted-average number of common shares outstanding[2]	**1,872**	1,867	1,883
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**1,873**	1,868	1,884
Earnings per share of common stock - Basic	**$ (0.27)**	$ 2.46	$ 10.21
Diluted EPS Calculation			
Earnings available to common stockholders - Diluted[1]	**$ (497)**	$ 4,587	$ 19,241
Weighted-average number of common shares outstanding[2]	**1,872**	1,867	1,883
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**—**	7	14
Total weighted-average number of common shares outstanding	**1,873**	1,875	1,898
Earnings per share of common stock - Diluted	**$ (0.27)**	$ 2.45	$ 10.14

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

[2] Millions of shares; 10 million shares of employee-based awards were not included in the 2016 diluted EPS calculation as the result would be anti-dilutive.

Note 15

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 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 table on the following page:

	Year ended December 31		
	2016	2015	2014
Upstream			
United States	**$ (2,054)**	$ (4,055)	$ 3,327
International	**(483)**	2,094	13,566
Total Upstream	**(2,537)**	(1,961)	16,893
Downstream			
United States	**1,307**	3,182	2,637
International	**2,128**	4,419	1,699
Total Downstream	**3,435**	7,601	4,336
Total Segment Earnings	**898**	5,640	21,229
All Other			
Interest expense	**(168)**	—	—
Interest income	**58**	65	77
Other	**(1,285)**	(1,118)	(2,065)
Net Income (Loss) Attributable to Chevron Corporation	**$ (497)**	$ 4,587	$ 19,241

Segment Assets Segment assets do not include intercompany investments or receivables. Assets at year-end 2016 and 2015 are as follows:

	At December 31	
	2016	2015
Upstream		
United States[1]	**$ 42,596**	$ 46,383
International[1]	**164,068**	162,030
Goodwill	**4,581**	4,588
Total Upstream	**211,245**	213,001
Downstream		
United States[1]	**22,264**	21,404
International	**15,816**	14,982
Total Downstream	**38,080**	36,386
Total Segment Assets	**249,325**	249,387
All Other		
United States[1,2]	**4,852**	4,728
International	**5,901**	10,425
Total All Other	**10,753**	15,153
Total Assets – United States[1,2]	**69,712**	72,515
Total Assets – International[1]	**185,785**	187,437
Goodwill	**4,581**	4,588
Total Assets	**$ 260,078**	$ 264,540

[1] 2015 adjusted to conform to ASU 2015-17. Refer to Note 19, "Income Taxes" beginning on page FS-49.
[2] 2015 adjusted to conform to ASU 2015-03. Refer to Note 5, "New Accounting Standards" on page FS-34.

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2016, 2015 and 2014, are presented in the table on the next page. 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 insurance operations, real estate activities and technology companies.

	Year ended December 31		
	2016	2015	2014
Upstream			
United States	**$ 3,148**	$ 4,117	$ 7,455
Intersegment	**7,217**	8,631	15,455
Total United States	**10,365**	12,748	22,910
International	**13,262**	15,587	23,808
Intersegment	**9,518**	11,492	23,107
Total International	**22,780**	27,079	46,915
Total Upstream	**33,145**	39,827	69,825
Downstream			
United States	**40,366**	48,420	73,942
Excise and similar taxes	**4,335**	4,426	4,633
Intersegment	**16**	26	31
Total United States	**44,717**	52,872	78,606
International	**46,388**	54,296	86,848
Excise and similar taxes	**2,570**	2,933	3,553
Intersegment	**1,068**	1,528	8,839
Total International	**50,026**	58,757	99,240
Total Downstream	**94,743**	111,629	177,846
All Other			
United States	**145**	141	252
Intersegment	**960**	1,372	1,475
Total United States	**1,105**	1,513	1,727
International	**1**	5	3
Intersegment	**36**	37	28
Total International	**37**	42	31
Total All Other	**1,142**	1,555	1,758
Segment Sales and Other Operating Revenues			
United States	**56,187**	67,133	103,243
International	**72,843**	85,878	146,186
Total Segment Sales and Other Operating Revenues	**129,030**	153,011	249,429
Elimination of intersegment sales	**(18,815)**	(23,086)	(48,935)
Total Sales and Other Operating Revenues	**$ 110,215**	$ 129,925	$ 200,494

Segment Income Taxes Segment income tax expense for the years 2016, 2015 and 2014 is as follows:

	Year ended December 31		
	2016	2015	2014
Upstream			
United States	**$ (1,172)**	$ (2,041)	$ 2,043
International	**166**	1,214	9,217
Total Upstream	**(1,006)**	(827)	11,260
Downstream			
United States	**503**	1,320	1,302
International	**484**	1,313	467
Total Downstream	**987**	2,633	1,769
All Other	**(1,710)**	(1,674)	(1,137)

Total Income Tax Expense (Benefit)	**$**	**(1,729)**	$	132	$	11,892

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 16, on page FS-43. Information related to properties, plant and equipment by segment is contained in Note 17, on page FS-44.

Note 16

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		
	2016	2015	**2016**	2015	2014
Upstream					
Tengizchevroil	**$ 11,414**	$ 8,077	**$ 1,380**	$ 1,939	$ 4,392
Petropiar	**977**	679	**326**	180	26
Caspian Pipeline Consortium	**1,245**	1,342	**145**	162	191
Petroboscan	**982**	1,163	**(133)**	219	186
Angola LNG Limited	**2,744**	3,284	**(282)**	(417)	(311)
Other	**1,791**	2,158	**(193)**	135	229
Total Upstream	**19,153**	16,703	**1,243**	2,218	4,713
Downstream					
GS Caltex Corporation	**3,767**	3,620	**373**	824	420
Chevron Phillips Chemical Company LLC	**5,767**	5,196	**840**	1,367	1,606
Caltex Australia Ltd.	**—**	—	**—**	92	183
Other	**1,118**	1,077	**209**	186	180
Total Downstream	**10,652**	9,893	**1,422**	2,469	2,389
All Other					
Other	**(16)**	(18)	**(4)**	(3)	(4)
Total equity method	**$ 29,789**	$ 26,578	**$ 2,661**	$ 4,684	$ 7,098
Other at or below cost	**461**	532			
Total investments and advances	**$ 30,250**	$ 27,110			
Total United States	**$ 7,258**	$ 6,863	**$ 802**	$ 1,342	$ 1,623
Total International	**$ 22,992**	$ 20,247	**$ 1,859**	$ 3,342	$ 5,475

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, 2016, the company's carrying value of its investment in TCO was about $140 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. In July 2016, the company made a $2,000 long-term loan to TCO to fund the development of the Future Growth and Wellhead Pressure Management Project. See Note 8, on page FS-36, 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, 2016, the company's carrying value of its investment in Petropiar was approximately $150 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 $1,245, which includes long-term loans of $921 at year-end 2016. 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, 2016, the company's carrying value of its investment in Petroboscan was approximately $120 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. The company also has an outstanding long-term loan to Petroboscan of $626 at year-end 2016.

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.

Other Information "Sales and other operating revenues" on the Consolidated Statement of Income includes $5,786, $4,850 and $10,404 with affiliated companies for 2016, 2015 and 2014, respectively. "Purchased crude oil and products" includes $3,468, $4,240 and $6,735 with affiliated companies for 2016, 2015 and 2014, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $676 and $399 due from affiliated companies at December 31, 2016 and 2015, respectively. "Accounts payable" includes $383 and $286 due to affiliated companies at December 31, 2016 and 2015, 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 $3,535, $410 and $874 at December 31, 2016, 2015 and 2014, respectively.

	Affiliates			Chevron Share		
Year ended December 31	**2016**	2015	2014	**2016**	2015	2014
Total revenues	**$ 59,253**	$ 71,389	$ 123,003	**$ 27,787**	$ 33,492	$ 58,937
Income before income tax expense	**6,587**	13,129	20,609	**3,670**	6,279	9,968
Net income attributable to affiliates	**5,127**	10,649	14,758	**2,876**	4,691	7,237
At December 31						
Current assets	**$ 33,406**	$ 27,162	$ 35,662	**$ 13,743**	$ 10,657	$ 13,465
Noncurrent assets	**75,258**	71,650	70,817	**28,854**	26,607	26,053
Current liabilities	**24,793**	20,559	25,308	**8,996**	7,351	9,588
Noncurrent liabilities	**22,671**	18,560	17,983	**4,255**	3,909	4,211
Total affiliates' net equity	**$ 61,200**	$ 59,693	$ 63,188	**$ 29,346**	$ 26,004	$ 25,719

Note 17
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]		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Upstream												
United States	**$ 83,929**	$ 93,848	$ 96,850	**$ 39,710**	$ 43,125	$ 45,864	**$ 4,432**	$ 6,586	$ 9,688	**$ 6,576**	$ 8,545	$ 5,127
International	**214,557**	208,395	192,637	**125,502**	127,459	118,926	**12,084**	19,993	24,920	**11,247**	10,803	9,688
Total Upstream	**298,486**	302,243	289,487	**165,212**	170,584	164,790	**16,516**	26,579	34,608	**17,823**	19,348	14,815
Downstream												
United States	**22,795**	23,202	22,640	**10,196**	10,807	11,019	**528**	696	588	**956**	878	886
International	**9,350**	9,177	9,334	**4,094**	4,090	4,219	**375**	365	530	**332**	355	396
Total Downstream	**32,145**	32,379	31,974	**14,290**	14,897	15,238	**903**	1,061	1,118	**1,288**	1,233	1,282
All Other												
United States	**5,263**	5,500	5,673	**2,635**	2,859	3,077	**198**	357	581	**328**	439	680
International	**183**	155	155	**49**	56	68	**6**	5	25	**18**	17	16
Total All Other	**5,446**	5,655	5,828	**2,684**	2,915	3,145	**204**	362	606	**346**	456	696
Total United States	**111,987**	122,550	125,163	**52,541**	56,791	59,960	**5,158**	7,639	10,857	**7,860**	9,862	6,693
Total International	**224,090**	217,727	202,126	**129,645**	131,605	123,213	**12,465**	20,363	25,475	**11,597**	11,175	10,100
Total	**$336,077**	$340,277	$327,289	**$182,186**	$188,396	$183,173	**$ 17,623**	$ 28,002	$ 36,332	**$ 19,457**	$ 21,037	$ 16,793

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 2016. Australia had PP&E of $53,962, $49,205 and $41,012 in 2016, 2015, and 2014, respectively. Nigeria had PP&E of $17,922, $18,773 and $19,214 for 2016, 2015 and 2014, respectively.
2 Net of dry hole expense related to prior years' expenditures of $175, $1,573 and $371 in 2016, 2015 and 2014, respectively.
3 Depreciation expense includes accretion expense of $749, $715 and $882 in 2016, 2015 and 2014, respectively, and impairments of $3,186, $4,066 and $1,274 in 2016, 2015 and 2014, respectively.

Note 18

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 six 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

Background 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.

Lago Agrio Judgment 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. The reporting justice of the Constitutional Court heard oral arguments on the appeal on July 16, 2015.

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 on August 4, 2015, a panel of the U.S. Court of Appeals for the District of Columbia Circuit affirmed the District Court's decision. On September 28, 2015, the Court of Appeals denied the Government of Ecuador's request for full appellate court review of the Federal District Court's decision. On June 6, 2016, the United States Supreme Court denied the Government of Ecuador's petition for Writ of Certiorari. On July 22, 2016, the Government of Ecuador paid the $96 award, plus interest, resulting in a payment to Chevron of approximately $113.

Lago Agrio Plaintiffs' Enforcement Actions 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 and 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 to the Supreme Court of Canada and, on September 4, 2015, the Supreme Court dismissed the appeal and affirmed that the Ontario Superior Court of Justice has jurisdiction over Chevron and Chevron Canada Limited for purposes of the action. The recognition and enforcement proceeding and related preliminary motions are proceeding in the Ontario Superior Court of Justice. On January 20, 2017, the Ontario Superior Court of Justice granted Chevron Canada Limited’s and Chevron Corporation’s motions for summary judgment, concluding that the two companies are separate legal entities with separate rights and obligations. As a result, the Superior Court dismissed the recognition and enforcement claim against Chevron Canada Limited. Chevron Corporation still remains as a defendant in the action. On February 3, 2017, the Lago Agrio plaintiffs appealed the Superior Court's January 20, 2017 decision.

On June 27, 2012, the Lago Agrio plaintiffs filed a complaint against Chevron Corporation in the Superior Court of Justice in Brasilia, Brazil, seeking to recognize and enforce the Ecuadorian judgment. Chevron has answered the complaint. In accordance with Brazilian procedure, the matter was referred to the public prosecutor for a nonbinding opinion of the issues raised in the complaint. On May 13, 2015, the public prosecutor issued its nonbinding opinion and recommended that the Superior Court of Justice reject the plaintiffs' recognition and enforcement request, finding, among other things, that the Lago Agrio judgment was procured through fraud and corruption and cannot be recognized in Brazil because it violates Brazilian and international public order.

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, to which the Lago Agrio plaintiffs responded on December 29, 2015. On April 19, 2016, the public prosecutor in Argentina issued a non-binding opinion recommending to the National Court, First Instance, of Argentina that it reject the Lago Agrio plaintiffs' request to recognize the Ecuadorian judgment in Argentina.

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.

Company's Bilateral Investment Treaty Arbitration Claims 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 subsequently 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), and on January 20, 2016, the District Court denied the Republic's request. On April 13, 2016, the Republic of Ecuador appealed the decision.

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. The Tribunal held a hearing on April 29-30, 2014, to address remaining issues relating to Phase One, and on March 12, 2015, it issued a nonbinding decision that the Lago Agrio plaintiffs' complaint, on its face, includes claims not barred by the settlement agreement between the Republic of Ecuador and Texpet. In the same decision, the Tribunal deferred to Phase Two remaining issues from Phase One, including whether the Republic of Ecuador breached the 1995 settlement agreement and the remedies that are available to Chevron and Texpet as a result of that breach. Phase Two issues were addressed at a hearing held in April and May 2015. The Tribunal has not set a date for Phase Three, the damages phase of the arbitration.

Company's RICO Action 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 appealed the Federal District Court's decision, and, on April 20, 2015, a panel of the U.S. Court of Appeals for the Second Circuit heard oral arguments. On August 8, 2016, the Second Circuit issued a unanimous opinion affirming in full the judgment of the Federal District Court in favor of Chevron. On October 27, 2016, the Second Circuit denied the defendants' petitions for en banc rehearing of the opinion on their appeal.

Management's Assessment 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 19
Taxes

Income Taxes

	Year ended December 31		
	2016	2015	2014
Income tax expense (benefit)			
U.S. federal			
Current	**$ (623)**	$ (817)	$ 748
Deferred	**(1,558)**	(580)	1,330
State and local			
Current	**(15)**	(187)	336
Deferred	**(121)**	(109)	36
Total United States	**(2,317)**	(1,693)	2,450
International			
Current	**2,744**	2,997	9,235
Deferred	**(2,156)**	(1,172)	207
Total International	**588**	1,825	9,442
Total income tax expense (benefit)	**$ (1,729)**	$ 132	$ 11,892

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:

	2016	2015[1]	2014[1]
Income (loss) before income taxes			
United States	**$ (4,317)**	$ (2,877)	$ 6,296
International	**2,157**	7,719	24,906
Total income (loss) before income taxes	**(2,160)**	4,842	31,202
Theoretical tax (at U.S. statutory rate of 35%)	**(756)**	1,695	10,921
Equity affiliate accounting effect	**(704)**	(1,286)	(2,039)
Effect of income taxes from international operations	**608**	72	2,708
State and local taxes on income, net of U.S. federal income tax benefit	**(44)**	(74)	234
Prior year tax adjustments, claims and settlements	**(349)**	84	(76)
Tax credits	**(188)**	(35)	(68)
Other[2]	**(296)**	(324)	212
Total income tax expense (benefit)	**$ (1,729)**	$ 132	$ 11,892
Effective income tax rate	**80.0%**	2.7%	38.1%

[1] 2014 and 2015 conformed to 2016 presentation.
[2] Includes one-time tax benefits associated with changes in uncertain tax positions and valuation allowances.

The 2016 decline in income tax expense of $1,861, from an expense of $132 in 2015 to a benefit of $1,729 in 2016, is a result of the year-over-year reduction in total income before income tax expense, which is primarily due to effects of lower crude oil prices. The company's effective tax rate changed from 2.7 percent in 2015 to 80 percent in 2016. The change in effective tax rate is primarily a consequence of the mix effect resulting from the absolute level of earnings or losses and whether they arose in higher or lower tax rate jurisdictions.

The company records its deferred taxes on a tax-jurisdiction basis. The reported deferred tax balances are composed of the following:

	At December 31	
	2016	2015
Deferred tax liabilities		
Properties, plant and equipment	**$ 25,180**	$ 27,044
Investments and other	**5,222**	3,743
Total deferred tax liabilities	**30,402**	30,787
Deferred tax assets		
Foreign tax credits	**(10,976)**	(10,534)
Abandonment/environmental reserves	**(6,251)**	(6,880)
Employee benefits	**(4,392)**	(4,801)
Deferred credits	**(1,950)**	(1,810)
Tax loss carryforwards	**(6,030)**	(2,748)
Other accrued liabilities	**(510)**	(525)
Inventory	**(374)**	(120)
Miscellaneous	**(3,121)**	(2,525)
Total deferred tax assets	**(33,604)**	(29,943)
Deferred tax assets valuation allowance	**16,069**	15,412
Total deferred taxes, net	**$ 12,867**	$ 16,256

Deferred tax liabilities at the end of 2016 were essentially unchanged from year-end 2015. Deferred tax assets increased by approximately $3,700 in 2016. The increase primarily related to increased tax loss carryforwards.

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 2016, the company had tax loss carryforwards of approximately $16,538 and tax credit carryforwards of approximately $1,423, 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 2017 through 2036. U.S. foreign tax credit carryforwards of $10,976 will expire between 2017 and 2026.

At December 31, 2016 and 2015, deferred taxes were classified on the Consolidated Balance Sheet as follows:

	At December 31	
	2016	2015
Deferred charges and other assets	**$ (4,649)**	$ (3,909)
Noncurrent deferred income taxes	**17,516**	20,165
Total deferred income taxes, net	**$ 12,867**	$ 16,256

Effective January 1, 2016, Chevron early-adopted *Income Taxes (Topic 740), Balance Sheet Classification of Deferred Taxes (ASU 2015-17)*, on a retrospective basis. The standard provides that all deferred income taxes be classified as noncurrent on the Consolidated Balance Sheet. The prior requirement was to classify most deferred tax assets and liabilities based on the classification of the underlying asset or liability. The December 31, 2015, Consolidated Balance Sheet has been restated and the effects are reductions of $917 in "Prepaid expenses and other current assets," $603 in "Deferred charges and other assets," $996 in "Federal and other taxes on income," and $524 in "Noncurrent deferred income taxes."

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 $46,400 at December 31, 2016. 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 2016, 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, 2016, 2015 and 2014. 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.

	2016	2015	2014
Balance at January 1	**$ 3,042**	$ 3,552	$ 3,848
Foreign currency effects	**1**	(27)	(25)
Additions based on tax positions taken in current year	**245**	154	354
Additions/reductions resulting from current-year asset acquisitions/sales	**—**	—	(22)
Additions for tax positions taken in prior years	**181**	218	37
Reductions for tax positions taken in prior years	**(390)**	(678)	(561)
Settlements with taxing authorities in current year	**(36)**	(5)	(50)
Reductions as a result of a lapse of the applicable statute of limitations	**(12)**	(172)	(29)
Balance at December 31	**$ 3,031**	$ 3,042	$ 3,552

Approximately 74 percent of the $3,031 of unrecognized tax benefits at December 31, 2016, 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, 2016. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States – 2011, Nigeria – 2000, Angola – 2009 and Kazakhstan – 2007.

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

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, 2016, accruals of $424 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of $399 as of year-end 2015. Income tax expense associated with interest and penalties was $38, $195 and $4 in 2016, 2015 and 2014, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2016	2015	2014
United States			
Excise and similar taxes on products and merchandise	**$ 4,335**	$ 4,426	$ 4,633
Import duties and other levies	**9**	4	6
Property and other miscellaneous taxes	**1,680**	1,367	1,002
Payroll taxes	**252**	270	273
Taxes on production	**159**	157	349
Total United States	**6,435**	6,224	6,263
International			
Excise and similar taxes on products and merchandise	**2,570**	2,933	3,553
Import duties and other levies	**33**	40	45
Property and other miscellaneous taxes	**2,379**	2,548	2,277
Payroll taxes	**145**	161	172
Taxes on production	**106**	124	230
Total International	**5,233**	5,806	6,277
Total taxes other than on income	**$ 11,668**	$ 12,030	$ 12,540

Note 20
Short-Term Debt

	At December 31	
	2016	2015
Commercial paper[1]	**$ 10,410**	$ 8,252
Notes payable to banks and others with originating terms of one year or less	**50**	20
Current maturities of long-term debt[2]	**6,253**	1,486
Current maturities of long-term capital leases	**14**	17
Redeemable long-term obligations		
Long-term debt	**3,113**	3,152
Capital leases	**—**	—
Subtotal	**19,840**	12,927
Reclassified to long-term debt	**(9,000)**	(8,000)
Total short-term debt	**$ 10,840**	$ 4,927

1 Weighted-average interest rates at December 31, 2016 and 2015, were 0.74 percent and 0.26 percent, respectively.

2 2015 adjusted to conform to ASU 2015-03. Refer to Note 5, "New Accounting Standards" on page FS-34.

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, 2016, the company had no interest rate swaps on short-term debt.

At December 31, 2016, the company had $9,000 in committed credit facilities with various major banks that enable the refinancing of short-term obligations on a long-term basis. The credit facilities consist of a 364-day facility which enables borrowing of up to $6,900 or the company can convert any amounts outstanding into a term loan for a period of up to one year, and a $2,100 five-year facility expiring in December 2020. 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, 2016.

The company classified $9,000 and $8,000 of short-term debt as long-term at December 31, 2016 and 2015, respectively. 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 21

Long-Term Debt

Total long-term debt, excluding capital leases, at December 31, 2016, was $35,193. The company's long-term debt outstanding at year-end 2016 and 2015 was as follows:

	At December 31			
	2016		2015	
	Principal	**Unamortized discounts and debt issuance costs**	Principal	Unamortized discounts and debt issuance costs
3.191% notes due 2023	**$ 2,250**	**$ 4**	$ 2,250	$ 4
2.954% notes due 2026	**2,250**	**6**	—	—
Floating rate notes due 2017 (1.091%)[1]	**2,050**	**1**	2,050	2
1.104% notes due 2017	**2,000**	**1**	2,000	2
1.718% notes due 2018	**2,000**	**1**	2,000	2
2.355% notes due 2022	**2,000**	**5**	2,000	5
1.365% notes due 2018	**1,750**	**1**	1,750	2
1.961% notes due 2020	**1,750**	**2**	1,750	2
Floating rate notes due 2018 (1.310%)[1]	**1,650**	**2**	800	1
4.95% notes due 2019	**1,500**	**2**	1,500	2
1.561% notes due 2019	**1,350**	**2**	—	—
2.100% notes due 2021	**1,350**	**2**	—	—
1.790% notes due 2018	**1,250**	**1**	1,250	2
2.419% notes due 2020	**1,250**	**2**	1,250	2
1.345% notes due 2017	**1,100**	**—**	1,100	2
1.344% notes due 2017	**1,000**	**1**	1,000	1
2.427% notes due 2020	**1,000**	**1**	1,000	2
2.193% notes due 2019	**750**	**1**	750	1
2.566% notes due 2023	**750**	**1**	—	—
3.326% notes due 2025	**750**	**2**	750	2
2.411% notes due 2022	**700**	**1**	700	1
Floating rate notes due 2021 (1.599%)[1]	**650**	**1**	400	1
Floating rate notes due 2019 (1.316%)[2]	**400**	**1**	400	2
Floating rate notes due 2022 (1.472%)[2]	**350**	**—**	350	1
Amortizing bank loan due 2018 (1.527%)[1]	**178**	**—**	110	—
8.625% debentures due 2032	**147**	**1**	147	1
8.625% debentures due 2031	**108**	**1**	108	1
8% debentures due 2032	**75**	**1**	74	1
9.75% debentures due 2020	**54**	**—**	54	—
8.875% debentures due 2021	**40**	**—**	40	—
Medium-term notes, maturing from 2021 to 2038 (6.133%)[1]	**38**	**—**	38	—
0.889% notes due 2016	**—**	**—**	750	—
Floating rate notes due 2016	**—**	**—**	700	1
Total including debt due within one year	**32,490**	**44**	27,071	43
Debt due within one year	**(6,256)**	**(3)**	(1,487)	(1)
Reclassified from short-term debt	**9,000**		8,000	
Total long-term debt	**$ 35,234**	**$ 41**	$ 33,584	$ 42

[1] Weighted-average interest rate at December 31, 2016.
[2] Interest rate at December 31, 2016.

Chevron has an automatic shelf registration statement that expires in August 2018. This registration statement is for an unspecified amount of nonconvertible debt securities issued or guaranteed by the company.

Long-term debt with a principal balance of $32,490 matures as follows: 2017 – $6,256; 2018 – $6,722; 2019 – $4,000; 2020 – $4,054; 2021 – $2,054; and after 2021 – $9,404.

The company completed a bond issuance of $6,800 in May 2016.

Effective January 1, 2016, Chevron adopted ASU 2015-03 on a retrospective basis. The standard requires that debt issuance costs related to a recognized liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability. On the Consolidated Balance Sheet, long-term debt net of unamortized discounts and debt issuance costs was $35,193 at December 31, 2016, and $33,542 at December 31, 2015.

See Note 10, beginning on page FS-37, for information concerning the fair value of the company's long-term debt.

Note 22

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, 2016:

	2016	2015	2014
Beginning balance at January 1	**$ 3,312**	$ 4,195	$ 3,245
Additions to capitalized exploratory well costs pending the determination of proved reserves	**465**	869	1,591
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(119)**	(164)	(298)
Capitalized exploratory well costs charged to expense	**(118)**	(1,397)	(312)
Other reductions*	**—**	(191)	(31)
Ending balance at December 31	**$ 3,540**	$ 3,312	$ 4,195

* 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		
	2016	2015	2014
Exploratory well costs capitalized for a period of one year or less	**$ 445**	$ 489	$ 1,522
Exploratory well costs capitalized for a period greater than one year	**3,095**	2,823	2,673
Balance at December 31	**$ 3,540**	$ 3,312	$ 4,195
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*	**35**	39	51

* Certain projects have multiple wells or fields or both.

Of the $3,095 of exploratory well costs capitalized for more than one year at December 31, 2016, $1,939 (15 projects) is related to projects that had drilling activities underway or firmly planned for the near future. The $1,156 balance is related to 20 projects in areas requiring a major capital expenditure before production could begin and for which additional drilling efforts were not underway 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 $1,156 referenced above had the following activities associated with assessing the reserves and the projects' economic viability: (a) $190 (two projects) – undergoing front-end engineering and design with final investment decision expected within four years; (b) $107 (two projects) – development concept under review by government; (c) $816 (seven projects) – development alternatives under review; (d) $43 (nine projects) – miscellaneous activities for projects with smaller amounts suspended. While progress was being made on all 35 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. More than half of these decisions are expected to occur in the next five years.

The $3,095 of suspended well costs capitalized for a period greater than one year as of December 31, 2016, represents 160 exploratory wells in 35 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
1998-2005	$	311	29
2006-2010		684	40
2011-2015		2,100	91
Total	$	3,095	160

Aging based on drilling completion date of last suspended well in project:		Amount	Number of projects
2003-2008	$	212	4
2009-2012		437	8
2013-2016		2,446	23
Total	$	3,095	35

Note 23

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2016, 2015 and 2014 was $271 ($176 after tax), $312 ($203 after tax) and $287 ($186 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance shares and restricted stock units was $371 ($241 after tax), $32 ($21 after tax) and $71 ($46 after tax) for 2016, 2015 and 2014, respectively. No significant stock-based compensation cost was capitalized at December 31, 2016, or December 31, 2015.

Cash received in payment for option exercises under all share-based payment arrangements for 2016, 2015 and 2014 was $647, $195 and $527, respectively. Actual tax benefits realized for the tax deductions from option exercises were $21, $17 and $54 for 2016, 2015 and 2014, respectively.

Cash paid to settle performance shares and stock appreciation rights was $82, $104 and $204 for 2016, 2015 and 2014, respectively.

Awards under the Chevron Long-Term Incentive Plan (LTIP) may take the form of, but are not limited to, stock options, restricted stock, restricted stock units, stock appreciation rights, performance shares 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, 2016, the contractual terms vary between three years for the performance shares and restricted stock units, and 10 years for the stock options and stock appreciation rights. For awards that will be issued in 2017, contractual terms vary between three years for the performance shares and special restricted stock units, 5 years for standard restricted stock units and 10 years for the stock options and stock appreciation rights. Forfeitures for performance shares, restricted stock units, and stock appreciation rights are recognized as they occur. Forfeitures for stock options are estimated using historical forfeiture data dating back to 1990.

The fair market values of stock options and stock appreciation rights granted in 2016, 2015 and 2014 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2016	2015	2014
Expected term in years[1]	**6.3**	6.1	6.0
Volatility[2]	**21.7 %**	21.9 %	30.3 %
Risk-free interest rate based on zero coupon U.S. treasury note	**1.6 %**	1.4 %	1.9 %
Dividend yield	**4.5 %**	3.6 %	3.3 %
Weighted-average fair value per option granted	**$ 9.53**	$ 13.89	$ 25.86

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 2016 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Averaged Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at January 1, 2016	94,292	$ 96.67		
Granted	30,913	$ 83.31		
Exercised	(8,589)	$ 75.57		
Forfeited	(4,341)	$ 86.81		
Outstanding at December 31, 2016	112,275	$ 94.99	6.13	$ 2,550
Exercisable at December 31, 2016	71,153	$ 97.32	4.66	$ 1,450

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2016, 2015 and 2014 was $240, $120 and $398, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2016, there was $169 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, 2016, the number of LTIP performance units outstanding was equivalent to 2,192,937 shares. During 2016, 1,019,900 units were granted, 718,472 units vested with cash proceeds distributed to recipients and 100,937 units were forfeited. At December 31, 2016, units outstanding were 2,393,428. The fair value of the liability recorded for these instruments was $381, and was measured using the Monte Carlo simulation method. In addition, outstanding stock appreciation rights and other awards that were granted under various LTIP programs totaled approximately 5.4 million equivalent shares as of December 31, 2016. A liability of $125 was recorded for these awards.

Note 24

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 benefit (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. Beginning in 2017, medical coverage for Medicare-eligible retirees in the company's main U.S. medical plan is provided through a third-party private exchange. The increase to the pre-Medicare 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 OPEB plans for 2016 and 2015 follows:

	Pension Benefits				Other Benefits	
	2016		2015			
	U.S.	**Int'l.**	U.S.	Int'l.	**2016**	2015
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 13,563**	**$ 5,336**	$ 14,250	$ 5,767	**$ 3,324**	$ 3,660
Service cost	**494**	**159**	538	185	**60**	72
Interest cost	**377**	**261**	502	277	**128**	151
Plan participants' contributions	**—**	**5**	—	6	**148**	148
Plan amendments	**—**	**—**	—	(6)	**(345)**	—
Actuarial (gain) loss	**903**	**426**	(345)	(309)	**(437)**	(326)
Foreign currency exchange rate changes	**—**	**(524)**	—	(326)	**8**	(37)
Benefits paid	**(2,066)**	**(494)**	(1,382)	(241)	**(337)**	(344)
Curtailment	**—**	**—**	—	(17)	**—**	—
Benefit obligation at December 31	**13,271**	**5,169**	13,563	5,336	**2,549**	3,324
Change in Plan Assets						
Fair value of plan assets at January 1	**10,274**	**4,109**	11,090	4,244	**—**	—
Actual return on plan assets	**936**	**642**	(75)	112	**—**	—
Foreign currency exchange rate changes	**—**	**(552)**	—	(239)	**—**	—
Employer contributions	**406**	**464**	641	227	**189**	196
Plan participants' contributions	**—**	**5**	—	6	**148**	148
Benefits paid	**(2,066)**	**(494)**	(1,382)	(241)	**(337)**	(344)
Fair value of plan assets at December 31	**9,550**	**4,174**	10,274	4,109	**—**	—
Funded status at December 31	**$ (3,721)**	**$ (995)**	$ (3,289)	$ (1,227)	**$ (2,549)**	$ (3,324)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and OPEB plans at December 31, 2016 and 2015, include:

	Pension Benefits				Other Benefits	
	2016		2015			
	U.S.	**Int'l.**	U.S.	Int'l.	**2016**	2015
Deferred charges and other assets	**$ 16**	**$ 199**	$ 13	$ 333	**$ —**	$ —
Accrued liabilities	**(222)**	**(75)**	(153)	(77)	**(163)**	(191)
Noncurrent employee benefit plans	**(3,515)**	**(1,119)**	(3,149)	(1,483)	**(2,386)**	(3,133)
Net amount recognized at December 31	**$ (3,721)**	**$ (995)**	$ (3,289)	$ (1,227)	**$ (2,549)**	$ (3,324)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and OPEB plans were $5,511 and $6,478 at the end of 2016 and 2015, respectively. These amounts consisted of:

	Pension Benefits				Other Benefits	
	2016		2015			
	U.S.	**Int'l.**	U.S.	Int'l.	**2016**	2015
Net actuarial loss	**$ 4,653**	**$ 1,145**	$ 4,809	$ 1,143	**$ (82)**	$ 367
Prior service (credit) costs	**4**	**106**	(5)	120	**(315)**	44
Total recognized at December 31	**$ 4,657**	**$ 1,251**	$ 4,804	$ 1,263	**$ (397)**	$ 411

The accumulated benefit obligations for all U.S. and international pension plans were $11,954 and $4,676, respectively, at December 31, 2016, and $12,032 and $4,684, respectively, at December 31, 2015.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2016 and 2015, was:

	Pension Benefits			
	2016		2015	
	U.S.	**Int'l.**	U.S.	Int'l.
Projected benefit obligations	**$ 13,208**	**$ 1,449**	$ 13,500	$ 1,623
Accumulated benefit obligations	**11,891**	**1,258**	11,969	1,357
Fair value of plan assets	**9,471**	**287**	10,198	207

The components of net periodic benefit cost and amounts recognized in the Consolidated Statement of Comprehensive Income for 2016, 2015 and 2014 are shown in the table below:

	Pension Benefits						Other Benefits		
	2016		2015		2014				
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.	**2016**	2015	2014
Net Periodic Benefit Cost									
Service cost	**$ 494**	**$ 159**	$ 538	$ 185	$ 450	$ 190	**$ 60**	$ 72	$ 50
Interest cost	**377**	**261**	502	277	494	340	**128**	151	148
Expected return on plan assets	**(723)**	**(243)**	(783)	(262)	(788)	(298)	**—**	—	—
Amortization of prior service costs (credits)	**(9)**	**14**	(8)	22	(9)	21	**14**	14	14
Recognized actuarial losses	**335**	**47**	356	78	209	96	**19**	34	7
Settlement losses	**511**	**6**	320	6	237	208	**—**	—	—
Curtailment losses (gains)	**—**	**—**	—	(14)	—	—	**—**	—	—
Total net periodic benefit cost	**985**	**244**	925	292	593	557	**221**	271	219
Changes Recognized in Comprehensive Income									
Net actuarial (gain) loss during period	**690**	**55**	513	(260)	2,233	(17)	**(430)**	(362)	514
Amortization of actuarial loss	**(846)**	**(53)**	(676)	(84)	(446)	(304)	**(19)**	(34)	(7)
Prior service (credits) costs during period	**—**	**—**	—	(6)	—	4	**(345)**	—	2
Amortization of prior service (costs) credits	**9**	**(14)**	8	(24)	9	(21)	**(14)**	(14)	(14)
Total changes recognized in other comprehensive income	**(147)**	**(12)**	(155)	(374)	1,796	(338)	**(808)**	(410)	495

Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 838**	**$ 232**	$ 770	$ (82)	$ 2,389	$ 219	**$ (587)**	$ (139)	$ 714

Net actuarial losses recorded in “Accumulated other comprehensive loss” at December 31, 2016, 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 11 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 2017, the company estimates actuarial losses of $340, $41 and $(5) 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 $408 will be recognized from "Accumulated other comprehensive loss" during 2017 related to lump-sum settlement costs from the main U.S. pension plans.

The weighted average amortization period for recognizing prior service costs (credits) recorded in "Accumulated other comprehensive loss" at December 31, 2016, was approximately 4 and 10 years for U.S. and international pension plans, respectively, and 11 years for OPEB plans. During 2017, the company estimates prior service (credits) costs of $(5), $12 and $(28) 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		
	2016		2015		2014				
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.	**2016**	2015	2014
Assumptions used to determine benefit obligations:									
Discount rate	**3.9%**	**4.3%**	4.0%	5.3%	3.7%	5.0%	**4.3%**	4.6%	4.3%
Rate of compensation increase	**4.5%**	**4.5%**	4.5%	4.8%	4.5%	5.1%	**N/A**	N/A	N/A
Assumptions used to determine net periodic benefit cost:									
Discount rate for service cost	**4.4%**	**5.3%**	3.7%	5.0%	4.3%	5.8%	**4.9%**	4.3%	4.9%
Discount rate for interest cost	**3.0%**	**5.3%**	3.7%	5.0%	4.3%	5.8%	**4.0%**	4.3%	4.9%
Expected return on plan assets	**7.3%**	**6.3%**	7.5%	6.3%	7.5%	6.6%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**4.8%**	4.5%	5.1%	4.5%	5.5%	**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 2016, the company used an expected long-term rate of return of 7.25 percent for U.S. pension plan assets, which account for 69 percent of the company's pension plan assets. In both 2015 and 2014, the company used a long-term rate of return of 7.5 percent for this plan.

The market-related value of assets of the main 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 OPEB plan obligations and expense reflect the rate at which benefits could be effectively settled, and are 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. Beginning with the December 31, 2015 measurement date, the projected cash flows were discounted to the valuation date using the yield curve for the main U.S. pension and OPEB plans. The effective discount rates derived from this analysis at the end of 2016 were 3.9 percent for the main U.S. pension plan and 4.1 percent for the main U.S. OPEB plan. The discount rates for these plans at the end of 2015 were 4.0 and 4.5 percent, respectively, while in 2014 they were 3.7 and 4.1 percent for these plans, respectively.

Beginning with the fiscal year ended December 31, 2016, the company changed the method used to estimate the service and interest cost associated with the company's main U.S. pension and OPEB plans. Under the new method, these costs are estimated by applying spot rates along the yield curve to the relevant projected cash flows. In prior years, the service and interest costs were estimated utilizing a single weighted-average discount rate derived from the yield curve used to measure the defined benefit obligations at the beginning of the year.

Other Benefit Assumptions For the measurement of accumulated postretirement benefit obligation at December 31, 2016, for the main U.S. OPEB plan, the assumed health care cost-trend rates start with 6.9 percent in 2017 and gradually decline to 4.5 percent for 2025 and beyond. For this measurement at December 31, 2015, the assumed health care cost-trend rates started with

7.1 percent in 2016 and gradually declined to 4.5 percent for 2025 and beyond. In both measurements, the annual increase to the company's pre-Medicare contributions upon retirement 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 pre-Medicare medical contributions for the main 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	$ 17	$ (15)
Effect on postretirement benefit obligation	$ 156	$ (128)

Plan Assets and Investment Strategy

The fair value measurements of the company's pension plans for 2016 and 2015 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, 2015								
Equities								
U.S.[1]	$ 1,699	$ 1,699	$ —	$ —	$ 392	$ 382	$ 10	$ —
International	1,302	1,296	6	—	457	435	22	—
Collective Trusts/Mutual Funds[2]	2,460	18	2,442	—	572	7	565	—
Fixed Income								
Government	257	46	211	—	1,089	93	996	—
Corporate	1,654	—	1,654	—	615	33	557	25
Bank Loans	148	—	148	—	—	—	—	—
Mortgage-Backed Securities	1	—	1	—	1	—	1	—
Other Asset Backed	1	—	1	—	—	—	—	—
Collective Trusts/Mutual Funds[2]	933	—	933	—	269	12	257	—
Mixed Funds[3]	—	—	—	—	85	4	81	—
Real Estate[4]	1,494	—	—	1,494	378	—	—	378
Cash and Cash Equivalents	253	253	—	—	232	232	—	—
Other[5]	72	(6)	26	52	19	(2)	19	2
Total at December 31, 2015	$ 10,274	$ 3,306	$ 5,422	$ 1,546	$ 4,109	$ 1,196	$ 2,508	$ 405
At December 31, 2016								
Equities								
U.S.[1]	**$ 1,217**	**$ 1,217**	**$ —**	**$ —**	**$ 565**	**$ 564**	**$ 1**	**$ —**
International	**1,832**	**1,822**	**10**	**—**	**576**	**576**	**—**	**—**
Collective Trusts/Mutual Funds[2]	**1,132**	**24**	**1,108**	**—**	**196**	**8**	**188**	**—**
Fixed Income								
Government	**222**	**—**	**222**	**—**	**1,125**	**51**	**1,074**	**—**
Corporate	**1,356**	**—**	**1,356**	**—**	**628**	**22**	**587**	**19**
Bank Loans	**118**	**—**	**107**	**11**	**—**	**—**	**—**	**—**
Mortgage-Backed Securities	**1**	**—**	**1**	**—**	**10**	**—**	**10**	**—**
Other Asset Backed	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Collective Trusts/Mutual Funds[2]	**1,031**	**—**	**1,031**	**—**	**320**	**—**	**320**	**—**
Mixed Funds[3]	**—**	**—**	**—**	**—**	**72**	**2**	**70**	**—**
Real Estate[4]	**1,367**	**—**	**—**	**1,367**	**331**	**—**	**—**	**331**
Alternative Investments[6]	**955**	**—**	**955**	**—**	**—**	**—**	**—**	**—**
Cash and Cash Equivalents	**252**	**243**	**9**	**—**	**331**	**325**	**6**	**—**
Other[5]	**67**	**(9)**	**25**	**51**	**20**	**—**	**18**	**2**
Total at December 31, 2016	**$ 9,550**	**$ 3,297**	**$ 4,824**	**$ 1,429**	**$ 4,174**	**$ 1,548**	**$ 2,274**	**$ 352**

1 U.S. equities include investments in the company's common stock in the amount of $12 at December 31, 2016, and $9 at December 31, 2015.

[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).

[6] Alternative investments focus on market-neutral strategies that have a low expected correlation to traditional asset classes. For these funds, the level 2 designation is mainly based on the restriction that advanced notification of redemptions, typically thirty days or less, is required.

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

	Fixed Income				
	Corporate	Bank Loans	Real Estate	Other	Total
Total at December 31, 2014	$ 22	$ —	$ 1,693	$ 57	$ 1,772
Actual Return on Plan Assets:					
Assets held at the reporting date	(3)	—	149	(1)	145
Assets sold during the period	—	—	23	—	23
Purchases, Sales and Settlements	6	—	7	(2)	11
Transfers in and/or out of Level 3	—	—	—	—	—
Total at December 31, 2015	$ 25	$ —	$ 1,872	$ 54	$ 1,951
Actual Return on Plan Assets:					
Assets held at the reporting date	**1**	**—**	**(85)**	**(1)**	**(85)**
Assets sold during the period	**—**	**—**	**121**	**1**	**122**
Purchases, Sales and Settlements	**(7)**	**11**	**(210)**	**(1)**	**(207)**
Transfers in and/or out of Level 3	**—**	**—**	**—**	**—**	**—**
Total at December 31, 2016	**$ 19**	**$ 11**	**$ 1,698**	**$ 53**	**$ 1,781**

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 90 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 30–60 percent, Fixed Income and Cash 20–65 percent, Real Estate 0–15 percent, and Alternative Investments 0–15 percent. The Alternative Investments range was expanded in 2016 to further diversify the portfolio. For the U.K. pension plan, the U.K. Board of Trustees has established the following asset allocation guidelines: Equities 30–50 percent, Fixed Income and Cash 35–70 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 factors, including market conditions and illiquidity constraints. 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 2016, the company contributed $406 and $464 to its U.S. and international pension plans, respectively. In 2017, the company expects contributions to be approximately $200 to its U.S. plans and $250 to its international pension plans. Actual contribution amounts are dependent upon investment returns, changes in pension obligations, regulatory environments, tax law changes 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 OPEB benefits of approximately $163 in 2017; $189 was paid in 2016.

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
2017	$ 1,502	$ 253	$ 163
2018	$ 1,362	$ 378	$ 163
2019	$ 1,310	$ 276	$ 164
2020	$ 1,267	$ 288	$ 164
2021	$ 1,234	$ 273	$ 164
2022-2026	$ 5,536	$ 1,542	$ 799

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 $281, $316 and $316 in 2016, 2015 and 2014, respectively.

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 2016, 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, 2016 and 2015, trust assets of $35 and $36, 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 $662, $690 and $965 in 2016, 2015 and 2014, 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 23, beginning on page FS-55.

Note 25

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 19, beginning on page FS-49, 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 has two guarantees to equity affiliates totaling $1,157. Of this amount, $749 is associated with a financing arrangement with an equity affiliate. Over the approximate 5-year remaining term of this guarantee, the maximum amount will be reduced as payments are made by the affiliate. The remaining amount of $408 is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 11-year remaining term of this 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 either 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: 2017 – $1,527; 2018 – $1,566; 2019 – $1,389; 2020 – $1,071; 2021 – $968; 2022 and after – $2,572. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $1,300 in 2016, $1,900 in 2015 and $3,700 in 2014.

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 operating, closed and divested sites, including, but not limited to, federal Superfund sites and analogous sites under state laws, refineries, chemical plants, marketing facilities, crude oil fields, and mining sites.

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

Chevron's environmental reserve as of December 31, 2016, was $1,467. Included in this balance was $284 related to remediation activities at approximately 146 sites for which the company had been identified as a potentially responsible party under the provisions of the federal Superfund law or analogous state laws which provide for joint and several liability for all responsible parties. Any future actions by 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 2016 environmental reserves balance of $1,183, $808 is related to the company's U.S. downstream operations, $51 to its international downstream operations, $322 to upstream operations and $2 to other businesses. Liabilities at all sites were primarily associated with the company's plans and activities to remediate soil or groundwater contamination or both.

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 2016 had a recorded liability that was material to the company's results of operations, consolidated financial position or liquidity.

Refer to Note 26 on page FS-62 for a discussion of the company's asset retirement obligations.

Other Contingencies 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 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 11 Chevron employees. These charges were dismissed by the trial court on February 19, 2013, reinstated by an appellate court on October 9, 2013, and then, upon Chevron's motion for reconsideration, dismissed by the appellate court on August 27, 2015. The federal district prosecutor has appealed the appellate court's decision.

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

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 significant gains or losses in future periods.

Note 26

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 2016, 2015 and 2014:

	2016	2015	2014
Balance at January 1	**$ 15,642**	$ 15,053	$ 14,298
Liabilities incurred	**204**	51	133
Liabilities settled	**(1,658)**	(981)	(1,291)
Accretion expense	**749**	715	882
Revisions in estimated cash flows	**(694)**	804	1,031
Balance at December 31	**$ 14,243**	$ 15,642	$ 15,053

In the table above, the amount associated with "Revisions in estimated cash flows" in 2016 reflects decreased cost estimates to abandon wells, equipment and facilities and delayed timing of abandonment. The long-term portion of the $14,243 balance at the end of 2016 was $13,447.

Note 27

Restructuring and Reorganization Costs

In 2015 and early 2016, the company recorded accruals for employee reduction programs related to the restructuring and reorganization of its corporate staffs and certain upstream operations. The employee reduction programs are substantially completed and the remaining payments are anticipated to be made in early 2017.

A before-tax charge of $353 was recorded in 2015 associated with these programs, of which $293 remained outstanding at December 31, 2015. During 2016, the company recorded an additional before-tax charge of $83 and made payments of $316 associated with these liabilities. The following table summarizes the accrued severance liability, which is classified as current on the Consolidated Balance Sheet:

	Amounts Before Tax
Balance at January 1, 2016	**$ 293**
Accruals/Adjustments	**83**
Payments	**(316)**
Balance at December 31, 2016	**$ 60**

Note 28

Other Financial Information

Earnings in 2016 included after-tax gains of approximately $800 relating to the sale of certain properties. Of this amount, approximately $600 and $200 related to downstream and upstream, respectively. Earnings in 2015 included after-tax gains of approximately $2,300 relating to the sale of certain properties, of which approximately $1,800 and $500 related to downstream and upstream assets, respectively. Earnings in 2016 included after-tax charges of approximately $2,900 for impairments and other asset write-offs related to upstream, and $110 related to downstream. Earnings in 2015 included after-tax charges of approximately $3,000 for impairments and other asset write-offs related to upstream.

Other financial information is as follows:

	Year ended December 31		
	2016	2015	2014
Total financing interest and debt costs	**$ 753**	$ 495	$ 358
Less: Capitalized interest	**552**	495	358
Interest and debt expense	**$ 201**	$ —	$ —
Research and development expenses	**$ 476**	$ 601	$ 707
Excess of replacement cost over the carrying value of inventories (LIFO method)	**2,942**	3,745	8,135
LIFO (losses) / profits on inventory drawdowns included in earnings	**(88)**	(65)	13
Foreign currency effects*	**$ 58**	$ 769	$ 487

* Includes $1, $344 and $118 in 2016, 2015 and 2014, respectively, for the company's share of equity affiliates' foreign currency effects.

The company has $4,581 in goodwill on the Consolidated Balance Sheet related primarily to the 2005 acquisition of Unocal. The company tested this goodwill for impairment during 2016 and no impairment was required.

Millions of dollars, except per-share amounts	**2016**	2015	2014	2013	2012
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues[1]	**$ 110,215**	$ 129,925	$ 200,494	$ 220,156	$ 230,590
Income from equity affiliates and other income	**4,257**	8,552	11,476	8,692	11,319
Total Revenues and Other Income	**114,472**	138,477	211,970	228,848	241,909
Total Costs and Other Deductions	**116,632**	133,635	180,768	192,943	195,577
Income Before Income Tax Expense (Benefit)	**(2,160)**	4,842	31,202	35,905	46,332
Income Tax Expense (Benefit)	**(1,729)**	132	11,892	14,308	19,996
Net Income	**(431)**	4,710	19,310	21,597	26,336
Less: Net income attributable to noncontrolling interests	**66**	123	69	174	157
Net Income (Loss) Attributable to Chevron Corporation	**$ (497)**	$ 4,587	$ 19,241	$ 21,423	$ 26,179
Per Share of Common Stock					
Net Income (Loss) Attributable to Chevron					
– Basic	**$ (0.27)**	$ 2.46	$ 10.21	$ 11.18	$ 13.42
– Diluted	**$ (0.27)**	$ 2.45	$ 10.14	$ 11.09	$ 13.32
Cash Dividends Per Share	**$ 4.29**	$ 4.28	$ 4.21	$ 3.90	$ 3.51
Balance Sheet Data (at December 31)					
Current assets[2]	**$ 29,619**	$ 34,430	$ 41,161	$ 48,909	$ 54,354
Noncurrent assets[2,3]	**230,459**	230,110	223,723	203,884	177,672
Total Assets	**260,078**	264,540	264,884	252,793	232,026
Short-term debt[3]	**10,840**	4,927	3,790	374	127
Other current liabilities[2]	**20,945**	20,540	27,322	32,061	33,488
Long-term debt and capital lease obligations[3]	**35,286**	33,622	23,994	20,027	12,045
Other noncurrent liabilities[2]	**46,285**	51,565	53,587	49,904	48,534
Total Liabilities	**113,356**	110,654	108,693	102,366	94,194
Total Chevron Corporation Stockholders' Equity	**$ 145,556**	$ 152,716	$ 155,028	$ 149,113	$ 136,524
Noncontrolling interests	**1,166**	1,170	1,163	1,314	1,308
Total Equity	**$ 146,722**	$ 153,886	$ 156,191	$ 150,427	$ 137,832

[1] Includes excise, value-added and similar taxes:	**$ 6,905**	$ 7,359	$ 8,186	$ 8,492	$ 8,010

[2] 2012-2015 adjusted to conform to ASU 2015-17. Refer to Note 19, "Income Taxes" beginning on page FS-49.

[3] 2012-2015 adjusted to conform to ASU 2015-03. Refer to Note 5, "New Accounting Standards" on page FS-34.

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 reserves and changes in

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, 2016									
Exploration									
Wells	**$ 707**	**$ 51**	**$ 95**	**$ 31**	**$ 1**	**$ 1**	**$ 886**	**$ —**	**$ —**
Geological and geophysical	**67**	**3**	**22**	**31**	**16**	**4**	**143**	**—**	**—**
Rentals and other	**139**	**40**	**70**	**57**	**54**	**32**	**392**	**—**	**—**
Total exploration	**913**	**94**	**187**	**119**	**71**	**37**	**1,421**	**—**	**—**
Property acquisitions[2]									
Proved	**16**	**—**	**—**	**52**	**—**	**—**	**68**	**—**	**—**
Unproved	**27**	**—**	**—**	**—**	**—**	**—**	**27**	**—**	**—**
Total property acquisitions	**43**	**—**	**—**	**52**	**—**	**—**	**95**	**—**	**—**
Development[3]	**3,814**	**1,631**	**2,014**	**1,866**	**3,733**	**550**	**13,608**	**2,211**	**262**
Total Costs Incurred[4]	**$ 4,770**	**$ 1,725**	**$ 2,201**	**$ 2,037**	**$ 3,804**	**$ 587**	**$ 15,124**	**$ 2,211**	**$ 262**
Year Ended December 31, 2015									
Exploration									
Wells	$ 857	$ 66	$ 172	$ 218	$ 81	$ 14	$ 1,408	$ —	$ —
Geological and geophysical	69	6	77	86	107	26	371	—	—
Rentals and other	218	56	121	109	71	68	643	—	—
Total exploration	1,144	128	370	413	259	108	2,422	—	—
Property acquisitions[2]									
Proved	23	21	—	54	—	—	98	—	—
Unproved	554	3	30	—	—	—	587	—	—
Total property acquisitions	577	24	30	54	—	—	685	—	—
Development[3]	6,275	2,048	3,701	3,924	6,715	995	23,658	1,641	225
Total Costs Incurred[4]	$ 7,996	$ 2,200	$ 4,101	$ 4,391	$ 6,974	$ 1,103	$ 26,765	$ 1,641	$ 225
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

1 Includes costs incurred whether capitalized or expensed. Excludes general support equipment expenditures. Includes capitalized amounts related to asset retirement obligations. See Note 26, "Asset Retirement Obligations," on page FS-62.

2 Does not include properties acquired in nonmonetary transactions.

3 Includes $481, $325 and $349 costs incurred prior to assignment of proved reserves for consolidated companies in 2016, 2015, and 2014, respectively.

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

	2016	2015	2014

Total cost incurred	$ 17.6	$ 28.6	$ 33.7	
Non-oil and gas activities	2.5	3.5	4.6	(Primarily includes LNG, gas-to-liquids and transportation activities.)
ARO	—	(1.0)	(1.2)	
Upstream C&E	$ 20.1	$ 31.1	$ 37.1	Reference page FS-13 Upstream total

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 16, beginning on page FS-43, 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, 2016									
Unproved properties	**$ 9,052**	**$ 3,063**	**$ 263**	**$ 1,273**	**$ 1,986**	**$ 23**	**$ 15,660**	**$ 108**	**$ —**
Proved properties and related producing assets	**69,924**	**18,269**	**38,903**	**56,070**	**11,642**	**10,738**	**205,546**	**8,484**	**3,898**
Support equipment	**2,249**	**357**	**1,083**	**2,036**	**8,598**	**131**	**14,454**	**1,632**	**—**
Deferred exploratory wells	**750**	**190**	**415**	**602**	**1,322**	**261**	**3,540**	**—**	**—**
Other uncompleted projects	**7,018**	**5,900**	**6,152**	**2,743**	**17,559**	**1,804**	**41,176**	**5,075**	**517**
Gross Capitalized Costs	**88,993**	**27,779**	**46,816**	**62,724**	**41,107**	**12,957**	**280,376**	**15,299**	**4,415**
Unproved properties valuation	**1,673**	**903**	**222**	**483**	**107**	**23**	**3,411**	**55**	**—**
Proved producing properties – Depreciation and depletion	**45,820**	**11,635**	**24,463**	**38,757**	**2,300**	**8,643**	**131,618**	**4,148**	**1,170**
Support equipment depreciation	**1,165**	**226**	**657**	**1,502**	**571**	**118**	**4,239**	**750**	**—**
Accumulated provisions	**48,658**	**12,764**	**25,342**	**40,742**	**2,978**	**8,784**	**139,268**	**4,953**	**1,170**
Net Capitalized Costs	**$ 40,335**	**$ 15,015**	**$ 21,474**	**$ 21,982**	**$ 38,129**	**$ 4,173**	**$ 141,108**	**$ 10,346**	**$ 3,245**
At December 31, 2015									
Unproved properties	$ 9,880	$ 3,216	$ 271	$ 1,487	$ 1,990	$ 23	$ 16,867	$ 108	$ —
Proved properties and related producing assets	79,891	16,810	36,563	51,509	3,012	9,664	197,449	7,803	3,857
Support equipment	1,970	363	1,229	1,967	1,195	176	6,900	1,452	—
Deferred exploratory wells	438	237	443	612	1,321	261	3,312	—	—
Other uncompleted projects	7,700	5,566	6,517	5,070	29,843	2,332	57,028	3,732	425
Gross Capitalized Costs	99,879	26,192	45,023	60,645	37,361	12,456	281,556	13,095	4,282
Unproved properties valuation	1,667	873	209	438	107	23	3,317	51	—
Proved producing properties – Depreciation and depletion	53,718	8,950	21,904	35,004	1,950	8,074	129,600	3,714	984
Support equipment depreciation	800	208	740	1,420	480	161	3,809	661	—
Accumulated provisions	56,185	10,031	22,853	36,862	2,537	8,258	136,726	4,426	984
Net Capitalized Costs	$ 43,694	$ 16,161	$ 22,170	$ 23,783	$ 34,824	$ 4,198	$ 144,830	$ 8,669	$ 3,298
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

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 2016, 2015 and 2014 are shown in the following table. Net income (loss) from exploration and production activities as reported on page FS-41 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-41.

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2016									
Revenues from net production									
Sales	**$ 1,178**	**$ 1,038**	**$ 238**	**$ 5,347**	**$ 733**	**$ 436**	**$ 8,970**	**$ 3,416**	**$ 695**
Transfers	**5,895**	**1,134**	**4,896**	**2,839**	**478**	**727**	**15,969**	**—**	**—**
Total	**7,073**	**2,172**	**5,134**	**8,186**	**1,211**	**1,163**	**24,939**	**3,416**	**695**
Production expenses excluding taxes	**(3,634)**	**(1,120)**	**(1,806)**	**(2,942)**	**(250)**	**(389)**	**(10,141)**	**(451)**	**(359)**
Taxes other than on income	**(341)**	**(90)**	**(104)**	**(10)**	**(154)**	**(2)**	**(701)**	**(494)**	**(67)**
Proved producing properties:									
Depreciation and depletion	**(5,913)**	**(2,729)**	**(2,612)**	**(3,848)**	**(425)**	**(483)**	**(16,010)**	**(524)**	**(196)**
Accretion expense[2]	**(265)**	**(26)**	**(134)**	**(181)**	**(30)**	**(66)**	**(702)**	**(3)**	**(12)**
Exploration expenses	**(399)**	**(132)**	**(255)**	**(109)**	**(70)**	**(38)**	**(1,003)**	**—**	**—**
Unproved properties valuation	**(342)**	**(31)**	**(13)**	**(44)**	**—**	**—**	**(430)**	**—**	**—**
Other income (expense)[3]	**681**	**(103)**	**(141)**	**(39)**	**4**	**431**	**833**	**(113)**	**(206)**
Results before income taxes	**(3,140)**	**(2,059)**	**69**	**1,013**	**286**	**616**	**(3,215)**	**1,831**	**(145)**
Income tax (expense) benefit	**1,080**	**139**	**(267)**	**(386)**	**(94)**	**(57)**	**415**	**(549)**	**39**
Results of Producing Operations	**$ (2,060)**	**$ (1,920)**	**$ (198)**	**$ 627**	**$ 192**	**$ 559**	**$ (2,800)**	**$ 1,282**	**$ (106)**
Year Ended December 31, 2015									
Revenues from net production									
Sales	$ 1,475	$ 1,155	$ 279	$ 6,254	$ 889	$ 403	$ 10,455	$ 4,097	$ 729
Transfers	7,195	1,089	6,182	3,779	408	829	19,482	—	—
Total	8,670	2,244	6,461	10,033	1,297	1,232	29,937	4,097	729
Production expenses excluding taxes	(4,293)	(1,162)	(1,758)	(3,601)	(162)	(505)	(11,481)	(510)	(365)
Taxes other than on income	(430)	(123)	(124)	(15)	(172)	(2)	(866)	(279)	(31)
Proved producing properties:									
Depreciation and depletion	(7,640)	(2,519)	(2,506)	(3,887)	(217)	(556)	(17,325)	(501)	(169)
Accretion expense[2]	(265)	(23)	(127)	(158)	(37)	(69)	(679)	(3)	(14)
Exploration expenses	(1,614)	(137)	(667)	(492)	(289)	(106)	(3,305)	—	(1)
Unproved properties valuation	(583)	(55)	(24)	(79)	(61)	—	(802)	—	—
Other income (expense)[3]	220	(291)	638	21	73	237	898	(25)	373
Results before income taxes	(5,935)	(2,066)	1,893	1,822	432	231	(3,623)	2,779	522
Income tax (expense) benefit	2,133	550	(986)	(679)	(178)	(62)	778	(835)	(291)
Results of Producing Operations	$ (3,802)	$ (1,516)	$ 907	$ 1,143	$ 254	$ 169	$ (2,845)	$ 1,944	$ 231

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 26, "Asset Retirement Obligations," on page FS-62.
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, 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

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 26, "Asset Retirement Obligations," on page FS-62.
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, 2016									
Average sales prices									
Liquids, per barrel	**$ 35.00**	**$ 43.89**	**$ 41.42**	**$ 37.55**	**$ 45.32**	**$ 39.64**	**$ 38.30**	**$ 31.83**	**$ 31.90**
Natural gas, per thousand cubic feet	**1.58**	**3.04**	**1.60**	**4.19**	**4.29**	**4.77**	**3.45**	**1.34**	**2.24**
Average production costs, per barrel[2]	**14.56**	**18.79**	**13.80**	**11.34**	**5.97**	**12.84**	**13.15**	**3.67**	**15.01**
Year Ended December 31, 2015									
Average sales prices									
Liquids, per barrel	$ 42.70	$ 49.66	$ 49.88	$ 46.19	$ 49.96	$ 48.53	$ 46.26	$ 38.71	$ 34.92
Natural gas, per thousand cubic feet	1.89	3.24	1.84	4.94	6.17	5.28	3.96	1.57	2.51
Average production costs, per barrel[2]	16.60	20.45	12.23	13.55	5.03	17.14	14.60	4.32	17.44
Year Ended December 31, 2014									
Average sales prices									
Liquids, per barrel	$ 84.13	$ 86.23	$ 96.43	$ 89.44	$ 95.17	$ 95.05	$ 89.44	$ 81.07	$ 76.07
Natural gas, per thousand cubic feet	3.90	3.25	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

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

Table V Reserve Quantity Information

Summary of Net Oil and Gas Reserves

	2016			2015			2014		
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.	**992**	**—**	**2,102**	933	—	2,683	955	—	2,743
Other Americas	**92**	**601**	**533**	109	594	597	103	531	739
Africa	**640**	**—**	**1,039**	702	—	1,100	701	—	1,112
Asia	**621**	**—**	**4,962**	660	—	4,933	584	—	4,607
Australia/Oceania	**124**	**—**	**9,176**	60	—	4,330	38	—	1,117
Europe	**77**	**—**	**213**	76	—	166	87	—	167
Total Consolidated	**2,546**	**601**	**18,025**	2,540	594	13,809	2,468	531	10,485
Affiliated Companies									
TCO	**920**	**—**	**1,402**	1,020	—	1,504	961	—	1,431
Other	**92**	**62**	**319**	91	58	288	100	51	317
Total Consolidated and Affiliated Companies	**3,558**	**663**	**19,746**	3,651	652	15,601	3,529	582	12,233
Proved Undeveloped									
Consolidated Companies									
U.S.	**420**	**—**	**1,574**	453	—	1,559	477	—	1,431
Other Americas	**131**	**3**	**114**	127	3	117	135	3	384
Africa	**236**	**—**	**1,788**	255	—	1,837	320	—	1,856
Asia	**99**	**—**	**571**	130	—	1,023	168	—	1,659
Australia/Oceania	**34**	**—**	**3,339**	93	—	7,543	104	—	9,824
Europe	**61**	**—**	**21**	67	—	58	79	—	68
Total Consolidated	**981**	**3**	**7,407**	1,125	3	12,137	1,283	3	15,222
Affiliated Companies									
TCO	**989**	**—**	**840**	656	—	764	654	—	746
Other	**26**	**108**	**767**	40	135	935	45	153	915
Total Consolidated and Affiliated Companies	**1,996**	**111**	**9,014**	1,821	138	13,836	1,982	156	16,883
Total Proved Reserves	**5,554**	**774**	**28,760**	5,472	790	29,437	5,511	738	29,116

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 Global Reserves, an organization that is separate from the Upstream operating organization. The Manager of Global Reserves has more than 30 years' experience working in the oil and gas industry and holds both undergraduate and graduate degrees in geoscience. His experience includes various technical and management roles in providing reserve and resource estimates in support of major capital and exploration projects, and more than 10 years of managing oil and gas reserves processes. He has been named a Distinguished Lecturer by the American Association of Petroleum Geologists and is an active member of the American Association of Petroleum Geologists, the SEPM Society of Sedimentary Geologists and the Society of Petroleum Engineers.

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 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 *Global 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 *Global Reserves Manual.* In addition, third-party engineering consultants are used to supplement the company's own reserves estimation controls and procedures, including through the use of third-party audits of selected oil and gas assets.

Technologies Used in Establishing Proved Reserves Additions In 2016, 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 2016, proved undeveloped reserves totaled 3.6 billion barrels of oil-equivalent (BOE), a decrease of 656 million BOE from year-end 2015. The decrease was due to the transfer of 1.1 billion BOE to proved developed, 7 million BOE in revisions and 7 million BOE in sales, partially offset by increases of 277 million BOE in improved recovery, 189 million BOE in extensions and discoveries and 10 million BOE in acquisitions.

During 2016, investments totaling approximately $8.8 billion in oil and gas producing activities and about $1.9 billion in non-oil and gas producing activities were expended to advance the development of proved undeveloped reserves. Australia accounted for about $2.3 billion of the total, mainly for development and construction activities at the Wheatstone LNG Project. Expenditures of about $2.3 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 $2.9 billion, primarily related to development projects of the TCO affiliate in Kazakhstan, and in Thailand. In Africa, about $1.6 billion was expended on various offshore development and natural gas projects in Nigeria, Angola and Republic of Congo. Development activities in Canada were primarily responsible for about $1.3 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 2016, the company held approximately 2.2 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 600 million BOE have remained undeveloped for five years or more related to the Gorgon and Wheatstone projects. 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 1.4 billion BOE of proved undeveloped reserves with about 1.0 billion BOE 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. In 2016, further reductions in commodity prices negatively impacted the economic limits of oil and gas properties, resulting in proved reserve decreases, and positively impacted proved reserves due to entitlement effects. The year-end reserves volumes have been updated for these circumstances and significant changes have been discussed in the appropriate reserves sections. For 2016, 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 32 percent and 45 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, 2016, 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, 2016, 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 2014, 2015 and 2016 are shown in the table on page FS-72 The company's estimated net proved reserves of natural gas are shown on page FS-73.

Noteworthy changes in liquids proved reserves for 2014 through 2016 are discussed below and shown in the table on the following page:

Revisions 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.

In 2015, entitlement effects and improved performance were responsible for the163 million barrel increase in the TCO affiliate in Kazakhstan. In Asia, entitlement effects and drilling performance across numerous assets resulted in the 164 million barrel increase. Improved field performance at various Nigerian fields, including Agbami, was primarily responsible for the 60 million barrel increase in Africa. Synthetic oil reserves in Canada increased by 80 million barrels, primarily due to entitlement effects.

In 2016, entitlement effects were mainly responsible for the 64 million barrel increase in the TCO affiliate in Kazakhstan. Improved field performance at various Gulf of Mexico fields, including Jack/St Malo, and in the San Joaquin Valley were primarily responsible for the 109 million barrel increase in the United States. In Asia, entitlement effects, drilling and improved performance across numerous assets resulted in the 50 million barrel increase.

Improved Recovery 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.

In 2016, improved recovery increased reserves by 293 million barrels, primarily due to the Future Growth Project in the TCO affiliate in Kazakhstan.

Extensions and Discoveries 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.

In 2015, extensions and discoveries in the Midland and Delaware basins were primarily responsible for the 137 million barrel increase in the United States.

In 2016, extensions and discoveries in the Midland and Delaware basins were primarily responsible for the 131 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.

In 2016, sales of 34 million barrels in the United States were primarily in the Gulf of Mexico shelf.

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

	Consolidated Companies								Affiliated Companies			Total Consolidated and Affiliated Companies
Millions of barrels	U.S.	Other Americas[1]	Africa	Asia	Australia/ Oceania	Europe	Synthetic Oil[2]	Total	TCO	Synthetic Oil	Other[3]	
Reserves at January 1, 2014	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
Changes attributable to:												
Revisions	(1)	(9)	60	164	14	(3)	80	305	163	—	(4)	464
Improved recovery	7	—	11	2	—	—	—	20	—	—	—	20
Extensions and discoveries	137	28	4	5	5	—	—	179	—	—	—	179
Purchases	—	—	—	—	—	—	—	—	—	—	—	—
Sales	(6)	—	(7)	—	—	—	—	(13)	—	—	—	(13)
Production	(183)	(21)	(132)	(133)	(8)	(20)	(17)	(514)	(102)	(11)	(10)	(637)
Reserves at December 31, 2015[4]	1,386	236	957	790	153	143	597	4,262	1,676	193	131	6,262
Changes attributable to:												
Revisions	**109**	**(20)**	**22**	**50**	**12**	**16**	**26**	**215**	**64**	**(12)**	**(5)**	**262**
Improved recovery	**5**	**—**	**11**	**2**	**—**	**—**	**—**	**18**	**273**	**—**	**2**	**293**
Extensions and discoveries	**131**	**23**	**9**	**1**	**—**	**—**	**—**	**164**	**—**	**—**	**—**	**164**
Purchases	**—**	**10**	**—**	**—**	**—**	**—**	**—**	**10**	**—**	**—**	**—**	**10**
Sales	**(34)**	**—**	**—**	**—**	**—**	**—**	**—**	**(34)**	**—**	**—**	**—**	**(34)**
Production	**(185)**	**(26)**	**(123)**	**(123)**	**(7)**	**(21)**	**(19)**	**(504)**	**(104)**	**(11)**	**(10)**	**(629)**
Reserves at December 31, 2016[4]	**1,412**	**223**	**876**	**720**	**158**	**138**	**604**	**4,131**	**1,909**	**170**	**118**	**6,328**

1 Ending reserve balances in North America were 169, 155 and 142 and in South America were 54, 81 and 96 in 2016, 2015 and 2014, respectively.
2 Reserves associated with Canada.
3 Ending reserve balances in Africa were 31, 34 and 37 and in South America were 87, 97 and 108 in 2016, 2015 and 2014, respectively.
4 Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-10 for the definition of a PSC). PSC-related reserve quantities are 19 percent, 20 percent and 19 percent for consolidated companies for 2016, 2015 and 2014, respectively.

Net Proved Reserves of Natural Gas

	Consolidated Companies							Affiliated Companies		Total Consolidated
Billions of cubic feet (BCF)	U.S.	Other Americas[1]	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other[2]	and Affiliated Companies
Reserves at January 1, 2014	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
Changes attributable to:										
Revisions	(66)	(435)	27	480	974	49	1,029	218	2	1,249
Improved recovery	1	—	—	—	—	—	1	—	—	1
Extensions and discoveries	659	147	61	61	118	—	1,046	—	—	1,046
Purchases	—	—	—	—	—	—	—	—	—	—
Sales	(48)	—	(5)	—	—	—	(53)	—	—	(53)
Production[3]	(478)	(121)	(114)	(851)	(160)	(60)	(1,784)	(127)	(11)	(1,922)
Reserves at December 31, 2015	4,242	714	2,937	5,956	11,873	224	25,946	2,268	1,223	29,437
Changes attributable to:										
Revisions	**(6)**	**(24)**	**(29)**	**443**	**853**	**72**	**1,309**	**111**	**(107)**	**1,313**
Improved recovery	**2**	**—**	**—**	**—**	**—**	**—**	**2**	**—**	**—**	**2**
Extensions and discoveries	**388**	**73**	**—**	**4**	**14**	**—**	**479**	**—**	**—**	**479**
Purchases	**4**	**3**	**—**	**—**	**—**	**—**	**7**	**—**	**—**	**7**
Sales	**(544)**	**(10)**	**—**	**—**	**—**	**—**	**(554)**	**—**	**—**	**(554)**
Production[3]	**(410)**	**(109)**	**(81)**	**(870)**	**(225)**	**(62)**	**(1,757)**	**(137)**	**(30)**	**(1,924)**
Reserves at December 31, 2016	**3,676**	**647**	**2,827**	**5,533**	**12,515**	**234**	**25,432**	**2,242**	**1,086**	**28,760**

1 Ending reserve balances in North America and South America were 172, 174, 59 and 475, 540, 1,064 in 2016, 2015 and 2014, respectively.
2 Ending reserve balances in Africa and South America were 939, 1,044, 1,043 and 147, 179, 189 in 2016, 2015 and 2014, respectively.
3 Total "as sold" volumes are 1,744, 1,742 and 1,695 for 2016, 2015 and 2014, respectively.
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 15 percent, 16 percent and 19 percent for consolidated companies for 2016, 2015 and 2014, respectively.

Noteworthy changes in natural gas proved reserves for 2014 through 2016 are discussed below and shown in the table above:

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

In 2015, positive drilling performance at Wheatstone and Gorgon was responsible for the 974 BCF increase in Australia. Net revisions of 480 BCF in Asia were primarily due to improved field performance in Thailand and to entitlement effects and improved performance in Kazakhstan. The majority of the net decrease of 435 BCF in Other Americas was due to the deferral of the infill drilling and compression projects as well as drilling results in Trinidad and Tobago. The 218 BCF increase for the TCO affiliate was due to entitlement effects and improved performance.

In 2016, development activities primarily at Wheatstone were responsible for the 853 BCF increase in Australia. Net revisions of 443 BCF in Asia were primarily due to improved field performance in China and Thailand.

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

In 2015, extensions and discoveries of 659 BCF in the United States were primarily in the Appalachian region and the Midland and Delaware basins.

In 2016, extensions and discoveries of 388 BCF in the United States were primarily in the Appalachian region and the Midland and Delaware basins.

Sales In 2016, sales of 544 BCF in the United States were primarily in the Gulf of Mexico shelf, Michigan and the midcontinent region.

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 (includes costs to retire existing wells and facilities in addition to those future wells and facilities necessary to produce proved undeveloped reserves), 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, 2016										
Future cash inflows from production	**$ 53,777**	**$ 33,520**	**$ 39,072**	**$ 44,526**	**$ 63,781**	**$ 6,338**	**$241,014**	**$ 66,506**	**$ 11,244**	**$ 318,764**
Future production costs	**(26,530)**	**(20,413)**	**(19,749)**	**(19,815)**	**(11,058)**	**(5,500)**	**(103,065)**	**(13,610)**	**(5,254)**	**(121,929)**
Future development costs	**(7,830)**	**(4,277)**	**(4,186)**	**(4,603)**	**(7,804)**	**(977)**	**(29,677)**	**(20,855)**	**(2,192)**	**(52,724)**
Future income taxes	**(3,454)**	**(2,664)**	**(9,684)**	**(8,503)**	**(13,476)**	**69**	**(37,712)**	**(9,613)**	**(1,639)**	**(48,964)**
Undiscounted future net cash flows	**15,963**	**6,166**	**5,453**	**11,605**	**31,443**	**(70)**	**70,560**	**22,428**	**2,159**	**95,147**
10 percent midyear annual discount for timing of estimated cash flows	**(5,086)**	**(3,670)**	**(1,380)**	**(3,137)**	**(15,264)**	**330**	**(28,207)**	**(13,901)**	**(972)**	**(43,080)**
Standardized Measure Net Cash Flows	**$ 10,877**	**$ 2,496**	**$ 4,073**	**$ 8,468**	**$ 16,179**	**$ 260**	**$ 42,353**	**$ 8,527**	**$ 1,187**	**$ 52,067**
At December 31, 2015										
Future cash inflows from production	$ 67,536	$ 39,363	$ 52,128	$ 58,645	$ 93,550	$ 8,561	$319,783	$ 75,378	$ 17,519	$ 412,680
Future production costs	(33,895)	(26,477)	(22,963)	(27,499)	(10,814)	(6,994)	(128,642)	(17,959)	(6,546)	(153,147)
Future development costs	(12,625)	(5,485)	(6,562)	(8,924)	(11,612)	(1,751)	(46,959)	(17,232)	(3,226)	(67,417)
Future income taxes	(4,161)	(2,316)	(14,681)	(9,229)	(21,337)	70	(51,654)	(12,056)	(3,460)	(67,170)
Undiscounted future net cash flows	16,855	5,085	7,922	12,993	49,787	(114)	92,528	28,131	4,287	124,946
10 percent midyear annual discount for timing of estimated cash flows	(5,871)	(2,830)	(2,230)	(3,673)	(26,179)	292	(40,491)	(15,249)	(2,239)	(57,979)
Standardized Measure Net Cash Flows	$ 10,984	$ 2,255	$ 5,692	$ 9,320	$ 23,608	$ 178	$ 52,037	$ 12,882	$ 2,048	$ 66,967
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

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	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2014	$ 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
Sales and transfers of oil and gas produced net of production costs	(17,145)	(3,637)	(20,782)
Development costs incurred	21,703	1,863	23,566
Purchases of reserves	2	—	2
Sales of reserves	(109)	—	(109)
Extensions, discoveries and improved recovery less related costs	1,415	—	1,415
Revisions of previous quantity estimates	9,171	3,607	12,778
Net changes in prices, development and production costs	(143,055)	(37,056)	(180,111)
Accretion of discount	18,179	4,965	23,144
Net change in income tax	52,355	9,357	61,712
Net change for 2015	(57,484)	(20,901)	(78,385)
Present Value at December 31, 2015	$ 52,037	$ 14,930	$ 66,967
Sales and transfers of oil and gas produced net of production costs	**(14,415)**	**(2,788)**	**(17,203)**
Development costs incurred	**12,732**	**2,473**	**15,205**
Purchases of reserves	**(41)**	**—**	**(41)**
Sales of reserves	**528**	**—**	**528**
Extensions, discoveries and improved recovery less related costs	**1,231**	**(917)**	**314**
Revisions of previous quantity estimates	**12,851**	**946**	**13,797**
Net changes in prices, development and production costs	**(37,198)**	**(9,798)**	**(46,996)**
Accretion of discount	**7,888**	**2,113**	**10,001**
Net change in income tax	**6,740**	**2,755**	**9,495**
Net change for 2016	**(9,684)**	**(5,216)**	**(14,900)**
Present Value at December 31, 2016	**$ 42,353**	**$ 9,714**	**$ 52,067**

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 September 30, 2015 filed as Exhibit 3.2 to Chevron Corporation's Current Report on Form 8-K filed September 30, 2015, 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	Amendment Number One to the Chevron Corporation Non-Employee Directors’ Equity Compensation and Deferral Plan, filed as Exhibit 10.1 to Chevron Corporation’s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2016, and incorporated herein by reference.
10.3	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.
10.4	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.
10.5	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.
10.6	Summary of Chevron Incentive Plan Award Criteria, filed as Exhibit 10.5 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference.
10.7	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.
10.8	Form of Non-Qualified Stock Options Award Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.1 to Chevron Corporation's Current Report on Form 8-K filed January 30, 2017, and incorporated herein by reference.
10.9	Form of Performance Share Award Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.2 to Chevron Corporation's Current Report on Form 8-K filed January 30, 2017, and incorporated herein by reference.
10.10	Form of Standard Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.3 to Chevron Corporation's Current Report on Form 8-K filed January 30, 2017, and incorporated herein by reference.
10.11	Form of Special Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.4 to Chevron Corporation's Current Report on Form 8-K filed January 30, 2017, and incorporated herein by reference.
10.12	Form of Restricted Stock Units Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.7 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference.
10.13	Form of Non-Qualified Stock Options Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.8 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference.
10.14	Form of Performance Shares Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.9 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference.
10.15	Form of Stock Appreciation Rights Grant Agreement under the Long-Term Incentive Plan of Chevron Corporation, filed as Exhibit 10.10 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2014, and incorporated herein by reference.

Exhibit No.	Description
10.16	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.
10.17	Chevron Corporation Deferred Compensation Plan for Management Employees II, filed as Exhibit 10.5 to Chevron Corporation's Annual Report on Form 10-K for the year ended December 31, 2008, and incorporated herein by reference.
10.18	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.
10.19	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.
10.20	Agreement between Chevron Corporation and R. Hewitt Pate, filed as Exhibit 10.16 to Chevron Corporation'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).
18.1*	Preferability letter provided by PricewaterhouseCoopers LLP (page E-4).
21.1*	Subsidiaries of Chevron Corporation (page E-5).
23.1*	Consent of PricewaterhouseCoopers LLP (page E-6).
24.1 to 24.10*	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 by the company's Chief Executive Officer (page E-7).
31.2*	Rule 13a-14(a)/15d-14(a) Certification by the company's Chief Financial Officer (page E-8).
32.1*	Rule 13a-14(b)/15d-14(b) Certification by the company's Chief Executive Officer (page E-9).
32.2*	Rule 13a-14(b)/15d-14(b) Certification by the company's Chief Financial Officer (page E-10).
99.1*	Definitions of Selected Energy and Financial Terms (pages E-11 through E-12).
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.