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, 2017
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, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth 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		Emerging growth company	o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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 — $197,705,630,543 (As of June 30, 2017)

Number of Shares of Common Stock outstanding as of February 12, 2018 — 1,910,253,256

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

Notice of the 2018 Annual Meeting and 2018 Proxy Statement, to be filed pursuant to Rule 14a-6(b) under the Securities Exchange Act of 1934, in connection with the company's 2018 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," "trends," "guidance," "focus," "on schedule," "on track," "is slated," "goals," "objectives," "strategies," "opportunities" 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 shares or the delay or failure of such transactions to close based on required closing conditions; 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 impact of the 2017 U.S. tax legislation on the company's future results; 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 19 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-2. As of December 31, 2017, Chevron had approximately 51,900 employees (including about 3,300 service station employees). Approximately 25,200 employees (including about 3,100 service station employees), or 49 percent, were employed in U.S. operations.

Overview of Petroleum Industry

Petroleum industry operations and profitability are influenced by many factors. Prices for crude oil, natural gas, petroleum products and petrochemicals are generally determined by supply and demand. Production levels from the members of the Organization of Petroleum Exporting Countries (OPEC), Russia and the United States are the major factors 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 30 through 37 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,” “us” and "its" 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, 2017, and assets as of the end of 2017 and 2016 — for the United States and the company's international geographic areas — are in Note 15 to the Consolidated Financial Statements beginning on page 67. Similar comparative data for the company's investments in and income from equity affiliates and property, plant and equipment are in Note 16 beginning on page 70 and Note 24 on page 87. Refer to page 41 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 95 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 2015 and each year-end from 2015 through 2017. 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, 2017, 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, 2017, 24 percent of the company's net proved oil-equivalent reserves were located in the United States, 21 percent were located in Australia and 20 percent were located in Kazakhstan.

The net proved reserve balances at the end of each of the three years 2015 through 2017 are shown in the following table:

	At December 31		
	2017	2016	2015
Liquids — Millions of barrels			
Consolidated Companies	**4,530**	4,131	4,262
Affiliated Companies	**2,012**	2,197	2,000
Total Liquids	**6,542**	6,328	6,262
Natural Gas — Billions of cubic feet			
Consolidated Companies	**27,514**	25,432	25,946
Affiliated Companies	**3,222**	3,328	3,491
Total Natural Gas	**30,736**	28,760	29,437
Oil-Equivalent — Millions of barrels*			
Consolidated Companies	**9,116**	8,369	8,586
Affiliated Companies	**2,549**	2,752	2,582
Total Oil-Equivalent	**11,665**	11,121	11,168

* 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 2017 and 2016 by the company and its affiliates. Worldwide oil-equivalent production of 2.728 million barrels per day in 2017 was up 5 percent from 2016. Production increases from major capital projects, base business, and shale and tight properties, were partially offset by production entitlement effects in several locations, normal field declines, and the impact of asset sales. Refer to the "Results of Operations" section beginning on page 34 for a detailed discussion of the factors explaining the 2015 through 2017 changes in production for crude oil and natural gas liquids, and natural gas, and refer to Table V on pages 98 and 99 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)	**2017**	2016	**2017**	2016	**2017**	2016
United States	**681**	691	**519**	504	**970**	1,120
Other Americas						
Argentina	**23**	26	**19**	20	**27**	32
Brazil	**13**	16	**12**	16	**4**	5
Canada[2]	**98**	92	**87**	83	**65**	55
Colombia	**16**	21	**—**	—	**96**	127
Trinidad and Tobago[3]	**5**	12	**—**	—	**29**	74
Total Other Americas	**155**	167	**118**	119	**221**	293
Africa						
Angola	**112**	114	**103**	106	**57**	52
Democratic Republic of the Congo	**2**	2	**2**	2	**1**	1
Nigeria	**250**	235	**213**	208	**223**	159
Republic of Congo	**38**	25	**36**	23	**14**	11
Total Africa	**402**	376	**354**	339	**295**	223
Asia						
Azerbaijan	**25**	32	**23**	30	**11**	13
Bangladesh	**111**	114	**4**	4	**642**	658
China	**30**	27	**17**	18	**81**	51
Indonesia	**164**	203	**137**	173	**163**	182
Kazakhstan	**55**	62	**33**	37	**132**	154
Myanmar	**19**	21	**—**	—	**116**	128
Partitioned Zone[4]	**—**	—	**—**	—	**—**	—
Philippines	**25**	26	**3**	3	**129**	138
Thailand	**241**	245	**69**	71	**1,031**	1,051
Total Asia	**670**	730	**286**	336	**2,305**	2,375
Australia/Oceania						
Australia	**256**	124	**27**	21	**1,372**	615
Total Australia/Oceania	**256**	124	**27**	21	**1,372**	615
Europe						
Denmark	**23**	22	**14**	14	**53**	48
United Kingdom	**75**	64	**50**	43	**155**	122
Total Europe	**98**	86	**64**	57	**208**	170
Total Consolidated Companies	**2,262**	2,174	**1,368**	1,376	**5,371**	4,796
Affiliates[2,5]	**466**	420	**355**	343	**661**	456
Total Including Affiliates[6]	**2,728**	2,594	**1,723**	1,719	**6,032**	5,252

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

[2] Includes synthetic oil: Canada, net	**51**	50	**51**	50	**—**	—
Venezuelan affiliate, net	**28**	28	**28**	28	**—**	—

[3] Producing fields in Trinidad and Tobago were sold in August 2017.

[4] Located between Saudi Arabia and Kuwait. Production has been shut-in since May 2015.

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

[6] Volumes include natural gas consumed in operations of 565 million and 486 million cubic feet per day in 2017 and 2016, respectively. Total "as sold" natural gas volumes were 5,467 million and 4,766 million cubic feet per day for 2017 and 2016, respectively.

Production Outlook

The company estimates its average worldwide oil-equivalent production in 2018 will grow 4 to 7 percent compared to 2017, assuming a Brent crude oil price of $60 per barrel and excluding the impact of anticipated 2018 asset sales. This estimate is subject to many factors and uncertainties, as described beginning on page 32. 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 94 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 2017, 2016 and 2015.

Gross and Net Productive Wells

The following table summarizes gross and net productive wells at year-end 2017 for the company and its affiliates:

	At December 31, 2017			
	Productive Oil Wells*		Productive Gas Wells *	
	Gross	Net	Gross	Net
United States	43,170	29,690	3,273	2,380
Other Americas	1,049	644	129	76
Africa	1,683	639	20	8
Asia	14,958	12,891	3,780	2,182
Australia/Oceania	564	315	95	26
Europe	325	71	170	36
Total Consolidated Companies	61,749	44,250	7,467	4,708
Affiliates	1,583	550	7	2
Total Including Affiliates	63,332	44,800	7,474	4,710
Multiple completion wells included above	819	551	38	32

* 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, 2017, 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	4,004	3,415	4,189	2,966	8,193	6,381
Other Americas	26,249	14,635	1,183	264	27,432	14,899
Africa	8,432	3,474	2,243	933	10,675	4,407
Asia	23,243	11,637	1,720	975	24,963	12,612
Australia/Oceania	25,947	17,198	2,002	803	27,949	18,001
Europe	2,004	1,004	407	53	2,411	1,057
Total Consolidated Companies	89,879	51,363	11,744	5,994	101,623	57,357
Affiliates	513	224	291	112	804	336
Total Including Affiliates	90,392	51,587	12,035	6,106	102,427	57,693

[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 2018, 2019 and 2020 if production is not established by certain required dates are 4,353, 1,695 and 1,321, 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 151 billion cubic feet of natural gas to third parties from 2018 through 2020. 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 2,380 billion cubic feet of natural gas to third parties from 2018 through 2020 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 91 for details associated with the company's development expenditures and costs of proved property acquisitions for 2017, 2016 and 2015.

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, 2017. A "development well" is a well drilled within the known area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

	Wells Drilling* at 12/31/17		Net Wells Completed 2017		2016		2015	
	Gross	**Net**	**Prod.**	**Dry**	**Prod.**	**Dry**	**Prod.**	**Dry**
United States	**220**	**167**	**435**	**4**	420	4	873	3
Other Americas	**30**	**13**	**40**	**—**	45	—	99	—
Africa	**4**	**1**	**34**	**—**	17	—	9	—
Asia	**9**	**1**	**246**	**2**	470	6	828	5
Australia/Oceania	**—**	**—**	**—**	**—**	4	—	4	—
Europe	**2**	**—**	**4**	**—**	3	—	2	—
Total Consolidated Companies	**265**	**182**	**759**	**6**	959	10	1,815	8
Affiliates	**41**	**17**	**36**	**—**	38	—	26	—
Total Including Affiliates	**306**	**199**	**795**	**6**	997	10	1,841	8

* 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 91 for detail on the company's exploration expenditures and costs of unproved property acquisitions for 2017, 2016 and 2015.

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, 2017. "Exploratory wells" are wells drilled to find and produce crude oil or natural gas in unknown 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.

	Wells Drilling* at 12/31/17		Net Wells Completed 2017		2016		2015	
	Gross	**Net**	**Prod.**	**Dry**	**Prod.**	**Dry**	**Prod.**	**Dry**
United States	**6**	**3**	**7**	**1**	4	1	16	4
Other Americas	**1**	**1**	**—**	**—**	4	—	5	1
Africa	**—**	**—**	**—**	**—**	1	1	3	—
Asia	**1**	**1**	**—**	**—**	3	—	5	1
Australia/Oceania	**—**	**—**	**—**	**—**	—	—	1	4
Europe	**—**	**—**	**—**	**1**	—	—	3	—
Total Consolidated Companies	**8**	**5**	**7**	**2**	12	2	33	10
Affiliates	**—**	**—**	**—**	**—**	—	—	—	—
Total Including Affiliates	**8**	**5**	**7**	**2**	12	2	33	10

* 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 2017 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 34, 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-8.

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 2017 averaged 681,000 barrels per day.

The company's activities in the midcontinent region are primarily in Colorado, New Mexico and Texas. During 2017, net daily production in these areas averaged 134,000 barrels of crude oil, 505 million cubic feet of natural gas and 50,000 barrels of natural gas liquids (NGLs). In 2017, the company divested properties in areas including Colorado, New Mexico, Oklahoma and Texas. The company is pursuing selected opportunities and actively transacting to create value.

In the Permian Basin of West Texas and southeast New Mexico, the company holds approximately 500,000 and 1,200,000 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 a series of horizontal wells that are completed concurrently using hydraulic fracture stimulation. In 2017, the company deployed a new basis of design, resulting in improved economics. The company is also applying data analytics and petrophysical technology on its Permian well information to drive improvements in well targets and performance. The company drilled 130 wells and participated in 180 nonoperated wells in the Midland and Delaware basins in 2017.

During 2017, net daily production in the Gulf of Mexico averaged 165,000 barrels of crude oil, 122 million cubic feet of natural gas and 13,000 barrels of NGLs. In 2017, the company divested its remaining operated offshore assets in the shelf area. All remaining shelf assets are non-operated interests. 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 2017 averaged 116,000 barrels of liquids (59,000 net) and 18 million cubic feet of natural gas (9 million net). Production ramp-up and development drilling for the first development phase was completed in 2017. In addition, development drilling continued on Stage 2, the second phase of the development plan, with three of the four planned wells completed. Stage 3 includes three additional development wells. Stage 3 drilling began in second quarter 2017; execution is expected to continue in 2018. Proved reserves have been recognized for these phases. Production from the Jack/St. Malo development is expected to ramp up to a total daily rate of 142,000 barrels of crude oil and 36 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 45,000 barrels of crude oil, 18 million cubic feet of natural gas, and 3,000 barrels of NGLs. Infill drilling continued in 2017. The Tahiti Vertical Expansion Project is the next development phase of the Tahiti Field, developing shallower reservoirs and encompassing four new wells and associated subsea infrastructure. All wells have been drilled, and facility installation work has commenced. First oil is expected in second-half 2018. Proved reserves have been recognized for this project. The Tahiti Field has an estimated production life of at least 20 years.

The company has a 15.6 percent nonoperated working interest in the deepwater Mad Dog Field. In 2017, 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 southwestern extension 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 2017, proved reserves have 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 (TLP) 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. The TLP has been moored in its final location; installation is expected to be completed in second quarter 2018. First oil is 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. Installation of the TLP and subsea infrastructure was completed in 2017, with first oil achieved in January 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 2017 and early 2018, the company participated in two appraisal wells and four exploration wells in the deepwater Gulf of Mexico. Chevron has operated working interests of 55 to 61.3 percent in the blocks containing the Anchor Field. The appraisal drilling program for the Anchor Field concluded in 2017 with the successful Anchor appraisal well. The company filed for Suspension of Production (SOP) in January 2018. The SOP is intended to hold the associated leases as the planned development matures. Activities are underway to mature a cost effective development plan.

Chevron is the operator of an exploration and appraisal program and potential development named Tigris, covering several 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. Activities are underway to mature the development plan. Exploration and appraisal activities have been completed at the 50 percent-owned Tiber and Guadalupe fields. The company has obtained an SOP for the Tiber Unit, and recently filed for an SOP on the Guadalupe Unit. Adjacent leases containing the Gibson prospect are expected to be part of the development.

During 2017 and early 2018, the company participated in successful discovery and appraisal wells at the nonoperated Whale prospect in the Perdido area, which resulted in a significant crude oil discovery. Chevron has a 40 percent working interest in the Whale prospect. Chevron announced a significant crude oil discovery in the 60 percent-owned and operated Ballymore prospect in January 2018. Ballymore is located in the Mississippi Canyon area, approximately 3 miles from Chevron's Blind Faith Platform. A sidetrack well is currently being drilled to further assess the discovery.

Chevron added 35 leases to its deepwater portfolio as a result of awards from the central Gulf of Mexico Lease Sale 247, held in March 2017, and Lease Sale 249, held in August 2017. Chevron also added 10 additional leases through asset swaps.

In California, the company has significant production in the San Joaquin Valley. In 2017, net daily production averaged 148,000 barrels of crude oil, 53 million cubic feet of natural gas and 2,000 barrels of NGLs.

The company holds approximately 423,000 net acres in the Marcellus Shale and 450,000 net acres in the Utica Shale, primarily located in southwestern Pennsylvania, eastern Ohio and the West Virginia panhandle. During 2017, net daily production in these areas averaged 290 million cubic feet of natural gas, 5,000 barrels of NGLs and 2,000 barrels of condensate. Chevron has implemented a factory development strategy, which enables co-development of the Marcellus and Utica shales from the same pads in stacked play locations.

Other Americas

“Other Americas” includes Argentina, Brazil, Canada, Colombia, Greenland, Mexico, Suriname and Venezuela. Net oil-equivalent production from these countries averaged 210,000 barrels per day during 2017.

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 2017 averaged 98,000 barrels per day, composed of 36,000 barrels of crude oil, 65 million cubic feet of natural gas and 51,000 barrels of synthetic oil from oil sands.

Chevron holds a 26.9 percent nonoperated working interest in the Hibernia Field and a 23.7 percent nonoperated working interest in the unitized Hibernia Southern Extension (HSE) areas offshore Atlantic Canada.

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 platform was installed at the offshore location in June 2017. First oil was achieved in November 2017. The project has an expected economic life of 30 years.

In the Flemish Pass Basin offshore Newfoundland, Chevron holds a 40 percent nonoperated working interest in two exploration blocks, EL1125 and EL1126. In addition, the company holds a 35 percent-owned and operated interest in 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 Quest carbon capture and storage facilities.

The company holds approximately 228,000 net acres in the Duvernay Shale in Alberta. Chevron has a 70 percent-owned and operated interest in most of the Duvernay acreage. Drilling continued during 2017 on an appraisal and land retention program. In November 2017, Chevron announced plans for the initial development program on approximately 55,000 net acres of its operated position in the Duvernay play. A total of 92 wells had been tied into production facilities by early 2018.

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 290,000 net acres in the Horn River and Liard shale gas basins in British Columbia. The horizontal appraisal drilling program progressed during 2017. 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 2017, proved reserves had not been recognized for this project.

Greenland Chevron held a 29.2 percent-owned and operated interest in two exploration blocks off the northeast coast of Greenland. The company informed the government of Greenland of its intent to relinquish these blocks in late 2017 following completion of a multi-year seismic program.

Mexico The company operates and holds a 33.3 percent working interest in Block 3 in the Perdido area of the Gulf of Mexico. The block covers 139,000 net acres. In 2017, activities for a seismic reprocessing project began. Chevron continues to evaluate additional exploration opportunities. In January 2018, a Chevron-led consortium was the successful bidder on an exploration license for Block 22 in the deepwater Cuenca Salina area of the Gulf of Mexico. Following license execution expected in May 2018, the company will operate and hold a 37.5 percent working interest in Block 22 which covers 267,000 net acres.

Argentina Chevron holds a 50 percent nonoperated interest in the Loma Campana and Narambuena concessions in the Vaca Muerta Shale covering 73,000 net acres. Chevron also holds an 85 percent-owned and operated interest in the El Trapial concession covering 94,000 net acres with both conventional production and Vaca Muerta Shale potential. Net oil-equivalent production in 2017 averaged 23,000 barrels per day, composed of 19,000 barrels of crude oil and 27 million cubic feet of natural gas.

Nonoperated development activities continued in 2017 at the Loma Campana concession in the Vaca Muerta Shale. During 2017, 24 horizontal wells were drilled, and the drilling program is expected to continue in 2018.

The company utilizes waterflood operations to mitigate declines at the operated El Trapial Field and continues to evaluate the potential of the Vaca Muerta Shale. The El Trapial concession expires in 2032. Chevron plans to start a shale appraisal program in late 2018.

Evaluation of the nonoperated Narambuena Block continued in 2017. Chevron was the successful bidder in November 2017 on the Loma del Molle Norte Block adjacent to the El Trapial concession.

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. In June 2017, the concession that includes the Frade Field was extended from 2025 to 2041, contingent on additional field development. The company is progressing a redevelopment plan. The concession that includes the Papa-Terra Field expires in 2032, and the remaining scope of the development plan is under evaluation. Drilling operations restarted at year-end 2017. Net oil-equivalent production in 2017 averaged 13,000 barrels per day, composed of 12,000 barrels of crude oil and 4 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. Final 3-D seismic data was received in second quarter 2017 and is being evaluated.

Colombia The company operates the offshore Chuchupa and onshore Ballena natural gas fields and receives 43 percent of the production for the remaining life of each field. Net production in 2017 averaged 96 million cubic feet of natural gas per day.

Suriname Chevron holds a 33.3 percent and a 50 percent nonoperated working interest in deepwater Blocks 42 and 45 offshore Suriname, respectively. An exploratory well is planned in Block 45 in 2018.

Trinidad and Tobago In August 2017, the company sold its nonoperated working interest in the East Coast Marine Area and its operated interest in the Manatee Field.

Venezuela Chevron's production activities in Venezuela are located in western Venezuela and the Orinoco Belt. Net oil-equivalent production during 2017 averaged 55,000 barrels per day, composed of 52,000 barrels of crude oil, and 15 million cubic feet of natural gas.

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 70 development wells in 2017. 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 26 development wells in 2017.

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 453,000 barrels per day during 2017 in this region.

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 2017, net production averaged 113,000 barrels of liquids and 302 million cubic feet of natural gas per day.

The main production facility of the second stage of the Mafumeira Field development was brought on line in February 2017 and production ramp-up is expected to continue through 2018. Water injection support began in May 2017, and gas export to Angola LNG began in July 2017.

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. 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. Total daily production in 2017 averaged 674 million cubic feet of natural gas (245 million net) and 27,000 barrels of NGLs (10,000 barrels net).

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. Production from Lianzi is reflected in the totals for Angola and Republic of Congo.

Democratic Republic of the Congo Chevron has a 17.7 percent nonoperated working interest in an offshore concession. In December 2017, the concession was extended 20 years, until 2043. Net production in 2017 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 36,000 barrels of liquids per day in 2017.

In March 2017, production started at the new TLP and floating production unit (FPU) facilities hub in the Moho-Bilondo development area. Miocene and Albian development drilling continued in 2017. Total daily production in 2017 averaged 72,000 barrels of crude oil (20,000 barrels net).

Two exploration wells are planned to be drilled in 2018, with one in the Moho Bilondo area and one in the 20.4 percent nonoperated working interest Haute Mer B area.

Liberia Chevron operates and holds a 45 percent interest in Block LB-14 off the coast of Liberia. The LB-14 PSC expires in 2018.

Morocco The company holds a 45 percent interest in two operated deepwater areas offshore Morocco. In 2017, the evaluation of 3-D seismic data continued. In 2017, the company surrendered its interest in the Cap Rhir Deep acreage.

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 2017, the company's net oil-equivalent production in Nigeria averaged 250,000 barrels per day, composed of 207,000 barrels of crude oil, 223 million cubic feet of natural gas and 6,000 barrels of liquefied petroleum gas.

Chevron operates and holds a 67.3 percent interest in the Agbami Field, located in deepwater Oil Mining Lease (OML) 127 and OML 128. The first two phases of infill drilling, Agbami 2 and Agbami 3, are complete. The third phase of infill drilling has commenced 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). Work continues on optimizing project scope and cost. At the end of 2017, 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. A 3-D seismic acquisition is planned for OML 140 in 2018. 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 2017, the company continued to evaluate development options for the multiple discoveries in the Usan area, including the Owowo Field that straddles OML 139 and OPL 223.

In the Niger Delta region, Chevron is executing a 36-well infill drilling program to offset oil decline and increase production. The program achieved net production of 13,000 barrels of crude oil per day at the end of 2017. 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 in 2017. Construction activities were completed in 2017 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. Production commenced in June 2017 and is expected to continue ramping up in 2018.

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 2017, net oil-equivalent production averaged 1,030,000 barrels per day in this region.

Azerbaijan Chevron holds a 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. In November 2017, the PSC was extended from 2024 to 2049. As part of the extension agreement, the company's interest in AIOC was reduced from 11.3 percent to 9.6 percent. Net oil-equivalent production in 2017 averaged 25,000 barrels per day, composed of 23,000 barrels of crude oil and 11 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 2017, WREP transported approximately 77,000 barrels per day from Baku, Azerbaijan, to a marine terminal at Supsa, Georgia, on the Black Sea.

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 2017 averaged 415,000 barrels per day, composed of 326,000 barrels of liquids and 533 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 2017 from these fields averaged 272,000 barrels of crude oil, 401 million cubic feet of natural gas and 21,000 barrels of NGLs. All of TCO's crude oil production was exported through the Caspian Pipeline Consortium (CPC) pipeline.

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 levels in existing plants as reservoir pressure declines. Project execution advanced through 2017. Fabrication of process modules is underway, and gas turbine generators are being constructed. Dredging is complete, and other activities for the initiation of port operations are underway. Infrastructure work and site construction are progressing, and three drilling rigs are in operation on the multi-well pads. First oil is planned for 2022. Proved reserves have been recognized for the FGP/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 2017, with project completion projected for second quarter 2018. 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. During 2017, net daily production averaged 33,000 barrels of liquids and 132 million cubic feet of natural gas. Most of the exported liquids were transported through the CPC pipeline. Work continues on identifying the optimal scope for the future expansion of the field. At year-end 2017, proved reserves had not been recognized for a future expansion.

Kazakhstan/Russia Chevron has a 15 percent interest in the CPC. During 2017, CPC transported an average of 1,180,000 barrels of crude oil per day, composed of 1,060,000 barrels per day from Kazakhstan and 120,000 barrels per day from Russia. In 2017, work was completed on the expansion of the pipeline, reaching the design capacity of 1.4 million per day. The expansion provides 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 2017 averaged 111,000 barrels per day, composed of 642 million cubic feet of natural gas and 4,000 barrels of condensate. In third quarter 2017, the company announced its intent to retain 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, Badamyar 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 natural gas to the Myanmar-Thailand border for delivery to power plants in Thailand. Net natural gas production in 2017 averaged 116 million cubic feet per day.

The Badamyar-Low Compression Platform (LCP) expansion project in Block M5 was brought on line in May 2017. The Badamyar-LCP is designed to maintain production from the Yadana Field by lowering wellhead pressure.

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 2017. Additional seismic processing and interpretation is expected in 2018.

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 2022 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 2017 averaged 241,000 barrels per day, composed of 69,000 barrels of crude oil and condensate and 1.0 billion cubic feet of natural gas.

In the Pattani Basin, the 35 percent-owned and operated Ubon Project in Block 12/27 entered front-end engineering and design (FEED) in third quarter 2017 with an updated development concept that optimizes oil and gas production profiles. At the end of 2017, proved reserves have not been recognized for this project.

During 2017, the company drilled two exploration wells in the Malay Basin, and both 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 2017 averaged 17,000 barrels of crude oil and 81 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. Total daily production in 2017 averaged 177 million cubic feet of natural gas (81 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 2017 averaged 25,000 barrels per day, composed of 129 million cubic feet of natural gas and 3,000 barrels of condensate. The concession expires in 2024.

In December 2017, the company sold its geothermal assets in the Philippines.

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. Net oil-equivalent production in 2017 averaged 164,000 barrels per day, composed of 137,000 barrels of liquids and 163 million cubic feet of natural gas. In 2016, Chevron advised the government of Indonesia of its intent not to extend the East Kalimantan PSC and to return the assets to the government upon PSC expiration in fourth quarter 2018.

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 2017. 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, includes a two-well subsea tieback to the West Seno FPU. The company's interest is 62 percent. Net daily production from Bangka in 2017 averaged 49 million cubic feet of natural gas and 2,000 barrels of condensate.

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. The project is being reviewed for opportunities to reduce project cost. At the end of 2017, proved reserves have not been recognized for this project.

In March 2017, the company sold its geothermal assets in Indonesia.

In August 2017, the company sold its South Natuna Sea Block B assets in Indonesia.

Kurdistan Region of Iraq The company operates and holds 80 percent contractor interests in the Sarta PSC. In fourth quarter 2017, drilling commenced on the first appraisal well. The well is planned to be completed in second-half 2018.

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 2018, production remains shut in, and the exact timing of a production restart is uncertain and dependent on dispute resolution between Saudi Arabia and Kuwait.

Processing of the 3-D seismic survey, which was acquired in 2016 and covers the entire onshore Partitioned Zone, was completed in second quarter 2017. Work continues to interpret the results.

Australia/Oceania

In Australia/Oceania, the company is engaged in upstream activities in Australia and New Zealand. During 2017, net oil-equivalent production averaged 256,000 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 2017, the company's production averaged 27,000 barrels of liquids and 1.4 billion 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. 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 3 start-up was achieved in March 2017. Total daily production from all three trains in 2017 averaged 1.9 billion cubic feet of natural gas (905 million net) and 14,000 barrels of condensate (7,000 barrels net). 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 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. LNG Train 1 start-up and first cargo were achieved in October 2017. Train 2 start-up operations are underway, and first LNG is expected in second quarter 2018. The project's estimated economic life exceeds 30 years.

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

During 2017, the company acquired 50 percent operated interests in four additional exploration permits in the northern Carnarvon Basin. Chevron expects to continue to evaluate exploration potential in the Carnarvon Basin during 2018.

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. In October 2017, the company discontinued the exploration program and informed the Government of Australia of the company's intent to exit from the Bight Basin.

New Zealand Chevron holds a 50 percent interest and operates three deepwater exploration permits in the offshore Pegasus and East Coast basins. Acquisition of 3-D seismic data was completed in second quarter 2017, and processing of the data is continuing.

Europe

In Europe, the company is engaged in upstream activities in Denmark, Norway and the United Kingdom. Net oil-equivalent production averaged 98,000 barrels per day during 2017.

Denmark Chevron holds a 12 percent nonoperated working interest in the Danish Underground Consortium, which produces crude oil and natural gas from 13 North Sea fields. The concession expires in 2042. Net oil-equivalent production in 2017 averaged 23,000 barrels per day, composed of 14,000 barrels of crude oil and 53 million cubic feet of natural gas.

United Kingdom The company’s net oil-equivalent production in 2017 averaged 75,000 barrels per day, composed of 50,000 barrels of liquids and 155 million cubic feet of natural gas.

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. In 2017, two polymer injection pilots were successfully completed and the company reached a final investment decision on Captain EOR Stage 1, which includes an expansion of the existing polymer injection system on the wellhead production platform, six new polymer injection wells and modifications to the platform facilities. At the end of 2017, proved reserves have been recognized for the Stage 1 project. Also during 2017, FEED activities continued to progress on Captain EOR Stage 2, which involves subsea expansion of the technology. At the end of 2017, proved reserves had not been recognized for Stage 2 of the project.

During 2017, hook-up and commissioning activities advanced 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 extending 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 selected design is a 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. FEED activities continued to progress in 2017, with focus on subsurface characterization and cost optimization. At the end of 2017, proved reserves had not been recognized for this project.

Norway The company holds a 20 percent nonoperated working interest in exploration Block PL 859, located in the Barents Sea. An exploration well was drilled in 2017, which resulted in noncommercial quantities of gas. A second well is scheduled for 2018 to further evaluate the potential of the license.

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 2017, U.S. and international sales of natural gas averaged 3.3 billion and 5.1 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 139,000 and 93,000 barrels per day, respectively, in 2017. 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 39 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 2017, the company had a refining network capable of processing nearly 1.7 million barrels of crude oil per day. Operable capacity at December 31, 2017, and daily refinery inputs for 2015 through 2017 for the company and affiliate refineries are summarized in the table on the next page.

Average crude oil distillation capacity utilization during 2017 was 93 percent, compared with 92 percent in 2016. At the U.S. refineries, crude oil distillation capacity utilization averaged 98 percent in 2017, compared with 93 percent in 2016. Chevron processes both imported and domestic crude oil in its U.S. refining operations. Imported crude oil accounted for about 71 percent and 76 percent of Chevron’s U.S. refinery inputs in 2017 and 2016, 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 continued to progress, with start-up of the new hydrogen plant scheduled for second-half 2018, and full operation of the project expected in 2019. At the Salt Lake City, Utah, refinery, construction began for the alkylation retrofit project in July 2017. Project start-up is expected in 2020.

Outside the United States, the Singapore Refining Company (SRC), Chevron's 50 percent-owned joint venture, completed construction of gasoline clean fuels facilities and a cogeneration plant. The two trains at the cogeneration plant were commissioned in first-half 2017, enabling SRC to generate its own electricity and steam supply, improve energy efficiency, and significantly reduce greenhouse gas and sulfur oxide emissions. The gasoline clean fuels facilities enable SRC to produce higher-value gasoline that meets stricter emission standards.

The company completed the sale of its refining assets in British Columbia, Canada, in September 2017. In addition, the company signed an agreement for the sale of its interests in the Cape Town Refinery in South Africa in 2017. The sale is expected to close in 2018, pending local government approval.

Petroleum Refineries: Locations, Capacities and Inputs

Capacities and inputs in thousands of barrels per day			December 31, 2017	Refinery Inputs		
Locations		**Number**	**Operable Capacity**	**2017**	**2016**	**2015**
Pascagoula	Mississippi	**1**	**340**	**349**	355	322
El Segundo	California	**1**	**269**	**251**	267	258
Richmond	California	**1**	**257**	**248**	188	245
Kapolei[1]	Hawaii	**—**	**—**	**—**	37	47
Salt Lake City	Utah	**1**	**53**	**53**	53	52
Total Consolidated Companies — United States		**4**	**919**	**901**	900	924
Map Ta Phut	Thailand	**1**	**165**	**152**	162	164
Cape Town[2]	South Africa	**1**	**110**	**68**	78	69
Burnaby, B.C.[3]	Canada	**—**	**—**	**40**	51	46
Total Consolidated Companies — International		**2**	**275**	**260**	291	279
Affiliates	Various Locations	**3**	**544**	**500**	497	499
Total Including Affiliates — International		**5**	**819**	**760**	788	778
Total Including Affiliates — Worldwide		**9**	**1,738**	**1,661**	1,688	1,702

1 In November 2016, the company sold the Hawaii Refinery.
2 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.
3 In September 2017, the company sold the Burnaby, B.C. refinery.

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, 2017.

Refined Products Sales Volumes

Thousands of barrels per day	**2017**	**2016**	**2015**
United States			
Gasoline	**625**	631	621
Jet Fuel	**242**	242	232
Diesel/Gas Oil	**179**	182	215
Residual Fuel Oil	**48**	59	59
Other Petroleum Products[1]	**103**	99	101
Total United States	**1,197**	1,213	1,228
International[2]			
Gasoline	**365**	382	389
Jet Fuel	**274**	261	271
Diesel/Gas Oil	**490**	468	478
Residual Fuel Oil	**162**	144	159
Other Petroleum Products[1]	**202**	207	210
Total International	**1,493**	1,462	1,507
Total Worldwide[2]	**2,690**	2,675	2,735

[1] Principally naphtha, lubricants, asphalt and coke.			
[2] Includes share of affiliates’ sales:	**366**	377	420

In the United States, the company markets under the Chevron and Texaco brands. At year-end 2017, the company supplied directly or through retailers and marketers approximately 7,700 Chevron- and Texaco-branded motor vehicle service stations, primarily in the southern and western states. Approximately 320 of these outlets are company-owned or -leased stations.

Outside the United States, Chevron supplied directly or through retailers and marketers approximately 5,800 branded service stations, including affiliates. 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. In 2017, the company opened Chevron branded stations in northwestern Mexico. In September 2017, the company completed the sale of its marketing assets in British Columbia and Alberta, Canada. The company also signed an agreement for the sale of its marketing and lubricants businesses in southern Africa in 2017. The sale is expected to close in 2018, pending local government approval.

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 2017, the company manufactured, blended or conducted research at 10 locations around the world. In November 2017, the company commissioned a new carboxylate plant in Singapore. In 2017, 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 2017, CPChem owned or had joint-venture interests in 30 manufacturing facilities and two research and development centers around the world.

During 2017, construction activities were completed 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 located at the Cedar Bayou facility and two polyethylene units located in Old Ocean, Texas, with a combined annual design capacity of one million metric tons. Start-up of the polyethylene units was achieved in September 2017. Mechanical completion of the ethane cracker was achieved in December 2017, with commissioning activities continuing in first quarter 2018 and transition to full production expected during second quarter 2018.

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.

All six of the new LNG carriers in support of the company's growing LNG portfolio are in service, with the final two delivered 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 27 beginning on page 89 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 19 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 45 for additional information on environmental matters and their impact on Chevron, and on the company's 2017 environmental expenditures. Refer to page 45 and Note 25 on page 88 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 production and inventory levels, technology advancements, production quotas or other actions that might be imposed by the Organization of Petroleum Exporting Countries (OPEC) or other producers, 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 organic opportunities 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; reservoir optimization; 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. These cyber threat actors are becoming more sophisticated and coordinated in their attempts to access the company's information technology (IT) systems and data, including the IT systems of cloud providers and third parties with which the company conducts business. Although Chevron devotes significant resources to prevent unwanted intrusions and to protect its systems and data, whether such data is housed internally or by external third parties, 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 its assets, access to its financial reporting systems, or loss, misuse or corruption of its critical data and proprietary information, including without limitation its intellectual property and business information and that of its employees, customers, partners and other third parties. Further, the company has exposure to cyber incidents and the negative impacts of such incidents related to its critical data and proprietary information housed on third-party IT systems, including the cloud. The company has limited control and visibility over such third-party IT systems. 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 potentially hazardous materials, and it purchases, handles and disposes of other potentially hazardous 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, see Note 17 to the Consolidated Financial Statements, beginning on page 71.

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 legal and 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. Further, Chevron is required to comply with U.S. sanctions laws and regulations which, depending upon their scope, could adversely impact the company's operations in certain 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. Like any significant changes in the regulatory environment, GHG 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 oil and gas continuing to make up a significant portion of the global energy mix through 2040 and beyond 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 and national, regional and state legislation (e.g., California AB32, SB32 and AB398) and regulatory measures 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 studying and adopting policies to meet their Paris Agreement goals. In some jurisdictions, the company is already subject to currently implemented programs such as the U.S. Renewable Fuel Standard program, the European Union Emissions Trading System, and the California cap-and-trade program and related low carbon fuel standard obligations. Other jurisdictions are considering adopting or are in the process of implementing laws or regulations to directly regulate GHG emissions through similar or other mechanisms such as, for example, via a carbon tax (e.g., Singapore and Canada) or via a cap-and-trade program (e.g., Mexico and China). The landscape continues to be in a state of constant re-assessment and legal challenge with respect to these laws and regulations, making it difficult to predict with certainty the ultimate impact they will have on the company in the aggregate.

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 additional 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 91 through 101. Note 24, "Properties, Plant and Equipment," to the company's financial statements is on page 87.

Item 3. Legal Proceedings

Governmental Proceedings 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. In addition, 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. In December 2017, Chevron and the SCAQMD entered into a settlement agreement to resolve allegations in six NOVs for a civil penalty of $375,500. In January 2018, Chevron and the SCAQMD entered into a settlement agreement to resolve allegations associated with the remaining three NOVs for a civil penalty of $5,137,250.

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. The United States Environmental Protection Agency (EPA) issued alleged findings of violation related to the incident on December 17, 2013, pursuant to its authority under the Clean Air Act Risk Management Plan program (RMP). Following the Richmond incident, EPA also 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 incident and subsequent RMP inspections. Resolution of those alleged findings of violation may result in the payment of a civil penalty of $100,000 or more.

As initially disclosed in the Annual Report on Form 10-K for the year ended December 31, 2016, 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.

As initially disclosed in the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, on November 18, 2016, Chevron received an Administrative Order (AO) from the EPA alleging noncompliance with the water permit that governed conveyances of captured groundwater and spring water from the former Questa mine located in New Mexico to its associated tailing facility. Chevron is concluding its negotiations with EPA regarding this matter.

As initially disclosed in the Quarterly Report on Form 10-Q for the quarter ended September 30, 2017, on August 3, 2017, Chevron received a Notice of Intent to File an Administrative Complaint from the EPA in connection with certain waste matters at the Kapolei, Hawaii refinery during the period of time that the facility was owned and operated by Chevron. Chevron is evaluating the allegations stated in the Notice. Resolution of these matters 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 October 26, 2017, Chevron received a proposal from the BAAQMD seeking to resolve certain NOVs related to violations that occurred at Chevron’s Richmond Refinery and Avon, California terminal in 2015. Resolution of the alleged violations may result in the payment of a civil penalty of $100,000 or more.

Other Proceedings Information related to other legal proceedings is included beginning on page 71 in Note 17 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 49.

Chevron Corporation Issuer Purchases of Equity Securities for Quarter Ended December 31, 2017

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, 2017	312	$117.42	—	—
Nov. 1 – Nov. 30, 2017	—		—	—
Dec. 1 – Dec. 31, 2017	—		—	—
Total Oct. 1 – Dec. 31, 2017	**312**	**$117.42**	**—**	**—**

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, 2016 or 2017.

Item 6. Selected Financial Data

The selected financial data for years 2013 through 2017 are presented on page 90.

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 29.

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 43 and in Note 11 to the Consolidated Financial Statements, "Financial and Derivative Instruments," beginning on page 65.

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 29.

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, 2017.

(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, 2017.

The effectiveness of the company's internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included on page 51.

(c) Changes in Internal Control Over Financial Reporting During the quarter ended December 31, 2017, 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 2017. 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 2018 and November 2018.

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 22, 2018

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
M.K. Wirth	57	Chairman of the Board and Chief Executive Officer (since February 2018) Vice Chairman of the Board and Executive Vice President, Midstream and Development (February 2017 to January 2018) Executive Vice President, Midstream and Development (February 2016 through January 2017) Executive Vice President, Downstream (2006 through 2015)	Chairman of the Board and Chief Executive Officer
J.W. Johnson	58	Executive Vice President, Upstream (since 2015) Senior Vice President, Upstream (2014) President, Europe, Eurasia and Middle East Exploration and Production (2011 through 2013)	Worldwide Exploration and Production Activities
P.R. Breber	53	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)	Worldwide Refining, Marketing and Lubricants; Chemicals
J.C. Geagea	58	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)	Technology; Health, Environment and Safety; Project Resources Company; Procurement
M.A. Nelson	54	Vice President, Midstream, Strategy and Policy (since February 2018) Vice President, Strategic Planning (May 2016 through January 2018) President, International Products (2010 through April 2016)	Corporate Strategy; Policy, Government and Public Affairs; Supply and Trading Activities; Shipping; Pipeline; Power and Energy Management
P.E. Yarrington	61	Vice President and Chief Financial Officer (since 2009)	Finance
R.H. Pate	55	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 2018 Annual Meeting of Stockholders and 2018 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 2018 Annual Meeting (the "2018 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 2018 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 2018 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 2018 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 2018 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 2018 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 2018 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 2018 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 2018 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 2018 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 2018 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 2018 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 2018" in the 2018 Proxy Statement is incorporated by reference into this Annual Report on Form 10-K.

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Key Financial Results

Millions of dollars, except per-share amounts		**2017**		2016		2015
Net Income (Loss) Attributable to Chevron Corporation	**$**	**9,195**	$	(497)	$	4,587
Per Share Amounts:						
Net Income (Loss) Attributable to Chevron Corporation						
– Basic	**$**	**4.88**	$	(0.27)	$	2.46
– Diluted	**$**	**4.85**	$	(0.27)	$	2.45
Dividends	**$**	**4.32**	$	4.29	$	4.28
Sales and Other Operating Revenues	**$**	**134,674**	$	110,215	$	129,925
Return on:						
Capital Employed		**5.0%**		(0.1)%		2.5%
Stockholders' Equity		**6.3%**		(0.3)%		3.0%

Earnings by Major Operating Area

Millions of dollars		**2017**		2016		2015
Upstream						
United States	**$**	**3,640**	$	(2,054)	$	(4,055)
International		**4,510**		(483)		2,094
Total Upstream		**8,150**		(2,537)		(1,961)
Downstream						
United States		**2,938**		1,307		3,182
International		**2,276**		2,128		4,419
Total Downstream		**5,214**		3,435		7,601
All Other		**(4,169)**		(1,395)		(1,053)
Net Income (Loss) Attributable to Chevron Corporation[1,2]	**$**	**9,195**	$	(497)	$	4,587
[1] Includes foreign currency effects:	**$**	**(446)**	$	58	$	769

[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 34 for a discussion of financial results by major operating area for the three years ended December 31, 2017.

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, 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. The downturn in the price of crude oil has impacted the company's results of operations, cash flows, leverage, capital and exploratory investment program and production outlook. A sustained lower price environment could result in the impairment or write-off of specific assets in future periods. The company has responded with reductions in operating expenses, 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 18 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 19 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

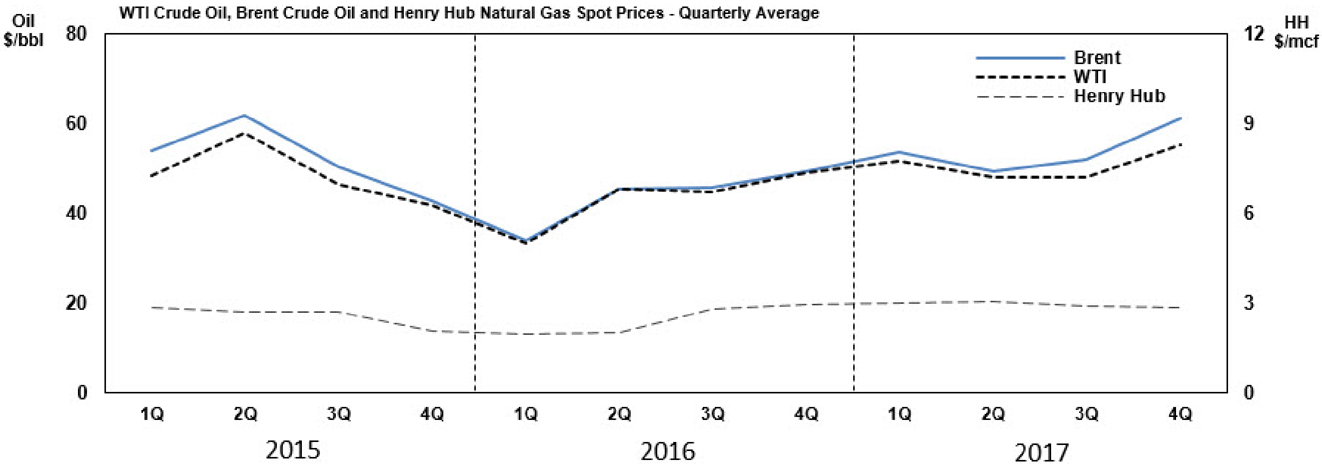
performance and value growth. The company's asset sale program for 2016 and 2017 targeted before-tax proceeds of $5-10 billion. Proceeds and deposits related to asset sales were $2.8 billion in 2016 and $5.2 billion in 2017. Refer to the “Results of Operations” section beginning on page 34 for discussions of net gains on asset sales during 2017. 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 production and inventory levels, technology advancements, production quotas or other actions imposed by the Organization of Petroleum Exporting Countries (OPEC) or other producers, 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. Industry cost inflation in most onshore segments, including North America unconventionals, started to modestly rise in 2017 with increases in commodity prices and higher levels of activity and investment. Offshore costs continue to decline driven by lower offshore activity levels and increased competition among suppliers. Capital and exploratory expenditures and operating expenses could 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 $54 per barrel for the full-year 2017, compared to $44 in 2016. As of mid-February 2018, the Brent price was $62 per barrel. The majority of the company’s equity crude production is priced based on the Brent benchmark. Crude oil prices were better supported in 2017 amid firming demand, rising geopolitical tensions, and ongoing output reductions by OPEC and certain non-OPEC producers. However, upside was limited as rebounding U.S. and other non-OPEC production resulted in ongoing oversupplied conditions. Prices weakened gradually over the first half of 2017 due to concerns that OPEC cuts would be allowed to expire in June 2017, but firmed over the second half of 2017 after OPEC's decision on May 25, 2017, to extend cuts through the first quarter of 2018. Price support was reinforced on November 30, 2017, when OPEC and their non-OPEC partners agreed to further extend output cuts through December 2018.

The WTI price averaged $51 per barrel for the full-year 2017, compared to $43 in 2016. As of mid-February 2018, the WTI price was $59 per barrel. WTI traded at a discount to Brent throughout 2017. After starting 2017 at a $2 discount to Brent, the WTI discount expanded to about $6 by year-end due to rising U.S. crude production, rebounding inventories, and growing concerns that pipeline infrastructure constraints would again restrict flows to export outlets on the Gulf Coast.

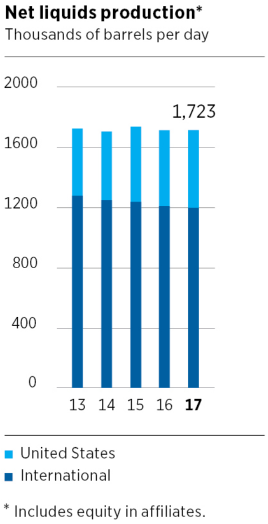
A differential in crude oil prices exists between high-gravity, low-sulfur crudes and low-gravity, high-sulfur crudes. The amount of the differential in any period is associated with the relative supply/demand balances for each crude type. In second-half 2017, the differential held generally steady in North America as robust refinery demand supported heavy crude values, while light sweet crude prices in the U.S. were supported by rising exports of domestic production. Outside of North America, differentials were steady to modestly wider amid well-supplied light sweet crude markets in the Atlantic Basin, while rising U.S. exports to Asia increased competitive pressure on Middle East exports to the region. Chevron has producing interests in 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 39 for the company's average U.S. and international crude oil realizations.)

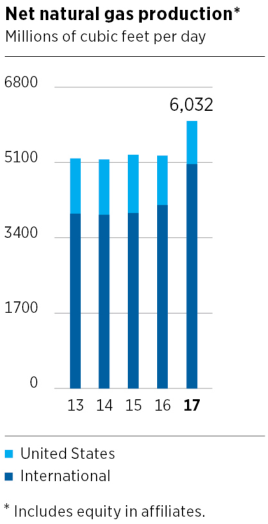
In contrast to price movements in the global market for crude oil, price changes for natural gas in many regional markets are more closely aligned with supply-and-demand conditions in those markets. Fluctuations in the price of natural gas in the United States are closely associated with customer demand relative to the volumes produced and stored in North America. In the United States, prices at Henry Hub averaged $2.97 per thousand cubic feet (MCF) during 2017, compared with $2.46 during 2016. As of mid-February 2018, the Henry Hub spot price was $2.57 per MCF.

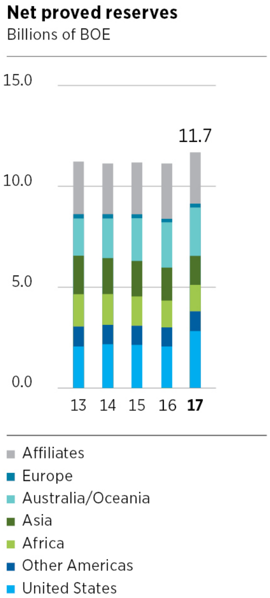
Outside the United States, price changes for natural gas depend on a wide range of supply, demand and regulatory circumstances. Chevron sells natural gas into the domestic pipeline market in most locations. In some locations, Chevron has invested in long-term projects to produce and liquefy natural gas 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 $4.62 per MCF during 2017, compared with $4.02 per MCF during 2016. (See page 39 for the company's average natural gas realizations for the U.S. and international regions.)

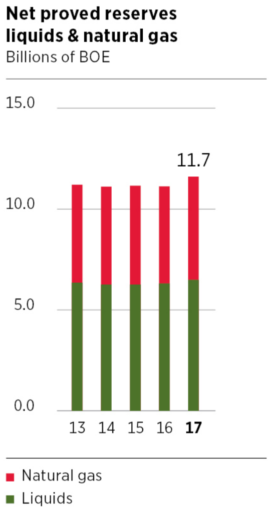
The company's worldwide net oil-equivalent production in 2017 averaged 2.728 million barrels per day. About one-sixth of the company's net oil-equivalent production in 2017 occurred in the OPEC-member countries of Angola, Nigeria and Venezuela. OPEC quotas had no effect on the company's net crude oil production in 2017 or 2016.

The company estimates that net oil-equivalent production in 2018 will grow 4 to 7 percent compared to 2017, assuming a Brent crude oil price of $60 per barrel and excluding the impact of anticipated 2018 asset sales. This estimate is subject to many factors and uncertainties, including 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.









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 2018, 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 2017 were not significant and are not expected to be significant in 2018.

Net proved reserves for consolidated companies and affiliated companies totaled 11.7 billion barrels of oil-equivalent at year-end 2017, an increase of 5 percent from year-end 2016. The reserve replacement ratio in 2017 was 155 percent. Refer to Table V beginning on page 95 for a tabulation of the company's proved net oil and gas reserves by geographic area, at the beginning of 2015 and each year-end from 2015 through 2017, and an accompanying discussion of major changes to proved reserves by geographic area for the three-year period ending December 31, 2017.

Refer to the "Results of Operations" section on pages 34 through 37 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 and Gulf Coast of the United States, 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 34 through 37 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 2017 and early 2018 included the following:

Upstream

Angola Commenced production from the main production facility of the Mafumeira Sul Project.

Australia Achieved start-up of Train 3 at the Gorgon LNG Project and Train 1 at the Wheatstone LNG Project.

Canada Achieved start-up of the Hebron Project.

Indonesia Completed the sale of the geothermal business.

United States Announced significant crude oil discoveries at the Whale and Ballymore prospects in the Gulf of Mexico.

Downstream

Canada Completed the sale of refining and marketing assets in British Columbia and Alberta.

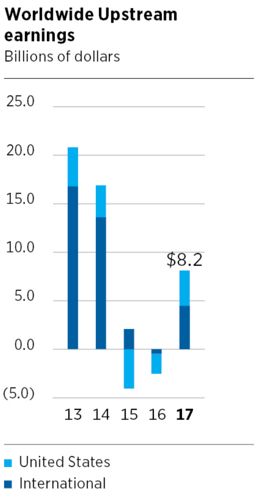
United States The company's 50 percent-owned affiliate, Chevron Phillips Chemical Company LLC achieved start-up of two polyethylene units and reached mechanical completion of a new ethane cracker at its U.S. Gulf Coast Petrochemicals Project in Texas.

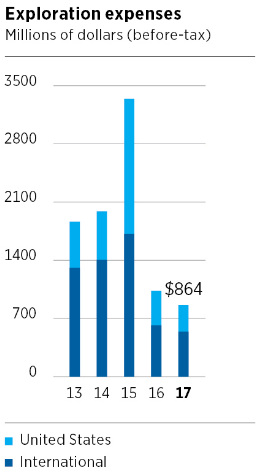
Other

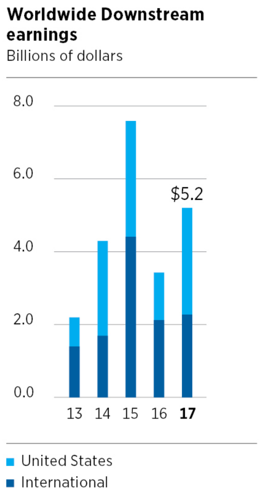
Common Stock Dividends The 2017 annual dividend was $4.32 per share, making 2017 the 30th consecutive year that the company increased its annual dividend payout. In January 2018, the company's Board of Directors approved a $0.04 per share increase in the quarterly dividend to $1.12 per share, payable in March 2018.

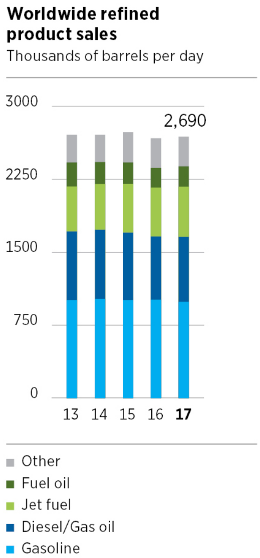
Results of Operations

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 67, 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 30 through 33.









U.S. Upstream

Millions of dollars		**2017**		2016		2015
Earnings	**$**	**3,640**	$	(2,054)	$	(4,055)

U.S. upstream earnings were $3.64 billion in 2017, compared with a loss of $2.05 billion in 2016. The improvement in earnings reflected a benefit of $3.33 billion from U.S. tax reform, higher crude oil and natural gas realizations of $1.3 billion and lower depreciation expenses of $650 million, primarily reflecting a decrease in impairments and other asset write-offs. Lower operating expenses of $140 million also contributed to the improvement.

U.S. upstream operations incurred a loss of $2.05 billion in 2016, compared with a loss of $4.06 billion from 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.

The company's average realization for U.S. crude oil and natural gas liquids in 2017 was $44.53 per barrel, compared with $35.00 in 2016 and $42.70 in 2015. The average natural gas realization was $2.10 per thousand cubic feet in 2017, compared with $1.59 in 2016 and $1.92 in 2015.

Net oil-equivalent production in 2017 averaged 681,000 barrels per day, down 1 percent from 2016 and down 5 percent from 2015. Between 2017 and 2016, production increases from shale and tight properties in the Permian Basin in Texas and New Mexico and base business in the Gulf of Mexico were more than offset by the effect of asset sales of 59,000 barrels per day and normal field declines. 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.

The net liquids component of oil-equivalent production for 2017 averaged 519,000 barrels per day, up 3 percent from 2016 and 4 percent from 2015. Net natural gas production averaged about 970 million cubic feet per day in 2017, down 13 percent from 2016 and 26 percent from 2015, primarily as a result of asset sales. Refer to the "Selected Operating Data" table on page 39 for a three-year comparison of production volumes in the United States.

International Upstream

Millions of dollars	**2017**	2016	2015
Earnings*	**$ 4,510**	$ (483)	$ 2,094
*Includes foreign currency effects:	**$ (456)**	$ 122	$ 725

International upstream earnings were $4.51 billion in 2017, compared with a loss of $483 million in 2016. The increase in earnings was primarily due to higher crude oil realizations of $2.59 billion, higher natural gas sales volumes of $1.22 billion, higher gains on asset sales of $750 million, and lower operating expenses of $410 million. Foreign currency effects had an unfavorable impact on earnings of $578 million between periods.

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 had an unfavorable impact on earnings of $603 million between periods.

The company's average realization for international crude oil and natural gas liquids in 2017 was $49.46 per barrel, compared with $38.61 in 2016 and $46.52 in 2015. The average natural gas realization was $4.62 per thousand cubic feet in 2017, compared with $4.02 and $4.53 in 2016 and 2015, respectively.

International net oil-equivalent production was 2.05 million barrels per day in 2017, up 8 percent from 2016 and 2015. Between 2017 and 2016, production increases from major capital projects and lower planned maintenance-related downtime were partially offset by production entitlement effects in several locations and normal field declines. 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.

The net liquids component of international oil-equivalent production was 1.20 million barrels per day in 2017, down 1 percent from 2016 and down 3 percent from 2015. International net natural gas production of 5.1 billion cubic feet per day in 2017 was up 23 percent from 2016 and 28 percent from 2015.

Refer to the "Selected Operating Data" table, on page 39, for a three-year comparison of international production volumes.

U.S. Downstream

Millions of dollars		**2017**		2016		2015
Earnings	**$**	**2,938**	$	1,307	$	3,182

U.S. downstream operations earned $2.94 billion in 2017, compared with $1.31 billion in 2016. The increase was primarily due to a $1.16 billion benefit from U.S. tax reform, higher margins on refined product sales of $380 million, lower operating expenses of $160 million, and the absence of an asset impairment of $110 million. Partially offsetting this increase were lower gains on asset sales of $90 million and lower earnings from the 50 percent-owned Chevron Phillips Chemicals Company LLC of $70 million, primarily reflecting the impacts from Hurricane Harvey.

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 an asset impairment of $110 million. Partially offsetting this decrease were lower operating expenses of $80 million and higher gains on asset sales of $110 million.

Refined product sales of 1.20 million barrels per day in 2017 were down 1 percent, primarily due to divestment of Hawaii refining and marketing assets in fourth quarter 2016. Sales volumes of refined products were 1.21 million barrels per day in 2016, a decrease of 1 percent from 2015, mainly reflecting lower sales of diesel. U.S. branded gasoline sales of 528,000 barrels per day in 2017 decreased 1 percent from 2016 and increased 1 percent from 2015.

Refer to the “Selected Operating Data” table on page 39 for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

International Downstream

Millions of dollars		**2017**		2016		2015
Earnings*	**$**	**2,276**	$	2,128	$	4,419
*Includes foreign currency effects:	**$**	**(90)**	$	(25)	$	47

International downstream earned $2.28 billion in 2017, compared with $2.13 billion in 2016. The increase in earnings was primarily due to higher gains on asset sales of $360 million, partially offset by higher operating expenses of $140 million. Foreign currency effects had an unfavorable impact on earnings of $65 million between periods.

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 had an unfavorable impact on earnings of $72 million between periods.

Total refined product sales of 1.49 million barrels per day in 2017 were up 2 percent from 2016, primarily due to higher diesel and jet fuel sales. 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.

Refer to the “Selected Operating Data” table, on page 39, for a three-year comparison of sales volumes of gasoline and other refined products and refinery input volumes.

All Other

Millions of dollars		**2017**		2016		2015
Net charges*	**$**	**(4,169)**	$	(1,395)	$	(1,053)
*Includes foreign currency effects:	**$**	**100**	$	(39)	$	(3)

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 2017 increased $2.77 billion from 2016, mainly due to higher tax items, primarily reflecting a $2.47 billion expense from U.S. tax reform, higher interest expense and a reclamation related charge for a former mining asset, partially offset by lower employee expense. Foreign currency effects decreased net charges by $139 million between periods. 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.

Consolidated Statement of Income

Comparative amounts for certain income statement categories are shown below:

Millions of dollars	**2017**	2016	2015
Sales and other operating revenues	**$ 134,674**	$ 110,215	$ 129,925

Sales and other operating revenues increased in 2017 mainly due to higher refined product and crude oil prices, higher crude oil volumes, and higher natural gas volumes. The decrease between 2016 and 2015 was primarily due to lower refined product and crude oil prices, partially offset by higher crude oil volumes.

Millions of dollars	**2017**	2016	2015
Income from equity affiliates	**$ 4,438**	$ 2,661	$ 4,684

Income from equity affiliates increased in 2017 from 2016 mainly due to higher upstream-related earnings from Tengizchevroil in Kazakhstan and Angola LNG.

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.

Refer to Note 16, beginning on page 70, for a discussion of Chevron’s investments in affiliated companies.

Millions of dollars	**2017**	2016	2015
Other income	**$ 2,610**	$ 1,596	$ 3,868

Other income of $2.6 billion in 2017 included net gains from asset sales of $2.2 billion before-tax. Other income in 2016 and 2015 included net gains from asset sales of $1.1 billion and $3.2 billion before-tax, respectively. Interest income was approximately $107 million in 2017, $145 million in 2016 and $119 million in 2015. Foreign currency effects decreased other income by $131 million in 2017, and $186 million in 2016 and increased other income $82 million in 2015.

Millions of dollars	**2017**	2016	2015
Purchased crude oil and products	**$ 75,765**	$ 59,321	$ 69,751

Crude oil and product purchases increased $16.4 billion in 2017 primarily due to higher crude oil and refined product prices, and higher refined product and crude oil volumes. The decrease between 2016 and 2015 of $10.4 billion was primarily due to lower crude oil and refined product prices, partially offset by an increase in crude oil volumes.

Millions of dollars	**2017**	2016	2015
Operating, selling, general and administrative expenses	**$ 23,885**	$ 24,952	$ 27,477

Operating, selling, general and administrative expenses decreased $1.1 billion between 2017 and 2016. The decrease included lower employee expenses of $690 million and non-operated joint venture expenses of $380 million.

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.

Millions of dollars	**2017**	2016	2015
Exploration expense	**$ 864**	$ 1,033	$ 3,340

Exploration expenses in 2017 decreased from 2016 primarily due to lower charges for well write-offs.

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.

Millions of dollars	**2017**	2016	2015
Depreciation, depletion and amortization	**$ 19,349**	$ 19,457	$ 21,037

Depreciation, depletion and amortization expenses decreased in 2017 from 2016 mainly due to lower impairments and lower depreciation rates for certain oil and gas producing properties, and the absence of a 2016 impairment of a downstream asset. Partially offsetting the decrease were higher production levels, accretion and write-offs for certain oil and gas producing fields, and a reclamation related charge for a former mining asset.

The decrease in 2016 from 2015 was 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.

Millions of dollars	**2017**	2016	2015
Taxes other than on income	**$ 12,331**	$ 11,668	$ 12,030

Taxes other than on income increased in 2017 from 2016 primarily due to higher duties, higher crude oil, refined product and natural gas sales, and higher production. 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.

Millions of dollars	**2017**	2016	2015
Income tax (benefit) expense	**$ (48)**	$ (1,729)	$ 132

The decline in income tax benefit in 2017 of $1.68 billion is due to the increase in total income before tax for the company of $11.38 billion and the remeasurement impacts of U.S. tax reform. U.S. losses before tax decreased from a loss of $4.32 billion in 2016 to a loss of $441 million in 2017. This decrease in losses before tax was primarily driven by the effect of higher crude oil prices. The U.S. tax benefit increased by $650 million between year-over-year periods from $2.32 billion in 2016 to $2.97 billion in 2017. The U.S. tax benefit for 2017 included a $2.02 billion benefit from U.S. tax reform, which primarily reflected the remeasurement of U.S. deferred tax assets and liabilities, and a reduction of $1.37 billion as result of the impact of a decrease in losses before tax of $3.88 billion. International income before tax increased from $2.16 billion in 2016 to $9.66 billion in 2017. This $7.50 billion increase was primarily driven by the effect of higher crude oil prices and gains on asset sales primarily in Indonesia and Canada. The higher crude prices primarily drove the $2.34 billion increase in international income tax expense between year-over-year periods, from $588 million in 2016 to $2.93 billion in 2017. Refer also to the discussion of the effective income tax rate in Note 18 on page 75.

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 18 on page 75.

Selected Operating Data[1,2]

		2017		2016		2015
U.S. Upstream						
Net Crude Oil and Natural Gas Liquids Production (MBPD)		**519**		504		501
Net Natural Gas Production (MMCFPD)[3]		**970**		1,120		1,310
Net Oil-Equivalent Production (MBOEPD)		**681**		691		720
Sales of Natural Gas (MMCFPD)		**3,331**		3,317		3,913
Sales of Natural Gas Liquids (MBPD)		**30**		30		26
Revenues from Net Production						
Liquids ($/Bbl)	**$**	**44.53**	$	35.00	$	42.70
Natural Gas ($/MCF)	**$**	**2.10**	$	1.59	$	1.92
International Upstream						
Net Crude Oil and Natural Gas Liquids Production (MBPD)[4]		**1,204**		1,215		1,243
Net Natural Gas Production (MMCFPD)[3]		**5,062**		4,132		3,959
Net Oil-Equivalent Production (MBOEPD)[4]		**2,047**		1,903		1,902
Sales of Natural Gas (MMCFPD)		**5,081**		4,491		4,299
Sales of Natural Gas Liquids (MBPD)		**29**		24		24
Revenues from Liftings						
Liquids ($/Bbl)	**$**	**49.46**	$	38.61	$	46.52
Natural Gas ($/MCF)	**$**	**4.62**	$	4.02	$	4.53
Worldwide Upstream						
Net Oil-Equivalent Production (MBOEPD)[4]						
United States		**681**		691		720
International		**2,047**		1,903		1,902
Total		**2,728**		2,594		2,622
U.S. Downstream						
Gasoline Sales (MBPD)[5]		**625**		631		621
Other Refined Product Sales (MBPD)		**572**		582		607
Total Refined Product Sales (MBPD)		**1,197**		1,213		1,228
Sales of Natural Gas Liquids (MBPD)		**109**		115		127
Refinery Input (MBPD)[6]		**901**		900		924
International Downstream						
Gasoline Sales (MBPD)[5]		**365**		382		389
Other Refined Product Sales (MBPD)		**1,128**		1,080		1,118
Total Refined Product Sales (MBPD)[7]		**1,493**		1,462		1,507
Sales of Natural Gas Liquids (MBPD)		**64**		61		65
Refinery Input (MBPD)[8]		**760**		788		778

[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):

	2017	2016	2015
United States	**37**	54	66
International	**528**	432	430

[4] Includes net production of synthetic oil:

	2017	2016	2015
Canada	**51**	50	47
Venezuela affiliate	**28**	28	29

[5] Includes branded and unbranded gasoline.

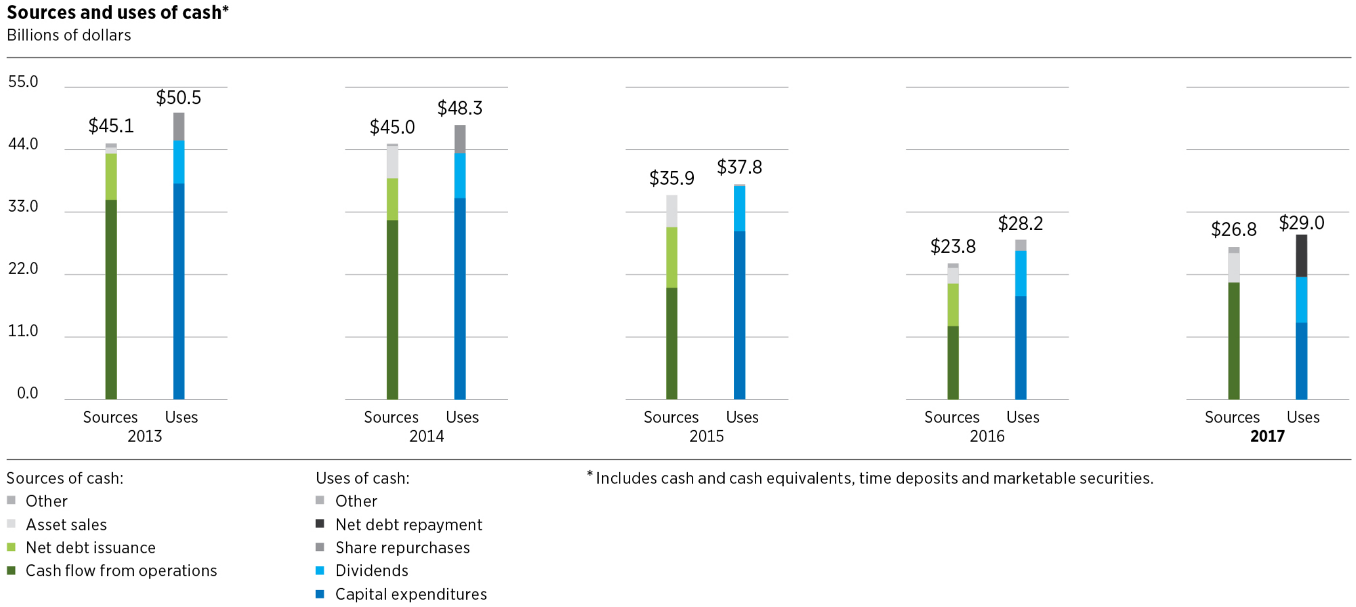
[6] In November 2016, the company sold its interests in the Hawaii Refinery which included operable capacity of 54,000 barrels per day.

[7] Includes sales of affiliates (MBPD): **366** (2017); 377 (2016); 420 (2015)

[8] In 2017, the company sold the Burnaby Refinery in British Columbia, Canada, which had operable capacity of 55,000 barrels per day. 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



Cash flow from operations increased $7.7 billion in 2017 primarily due to higher crude oil prices. The company also continued to reduce cash outlays and increase asset sales. Progress on these actions during 2017 included:

- Reducing cash capital expenditures to $13.4 billion, a 26 percent decrease compared to 2016,
- Reducing operating and administrative expenses by $1.1 billion, a 4 percent decrease compared to 2016, and
- Realizing net proceeds from asset sales of $5.2 billion during 2017.

The strength of the company's balance sheet enabled it to fund any timing differences throughout the year between cash inflows and outflows.

Cash, Cash Equivalents and Marketable Securities Total balances were $4.8 billion and $7.0 billion at December 31, 2017 and 2016, respectively. Cash provided by operating activities in 2017 was $20.5 billion, compared with $12.8 billion in 2016 and $19.5 billion in 2015, reflecting higher crude oil prices. Cash provided by operating activities was net of contributions to employee pension plans of approximately $1.0 billion in 2017 and $0.9 billion in both 2016 and 2015. Cash provided by investing activities included proceeds and deposits related to asset sales of $5.2 billion in 2017, $2.8 billion in 2016, and $5.7 billion in 2015.

Restricted cash of $1.1 billion and $1.4 billion at December 31, 2017 and 2016, 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 $8.1 billion in 2017, $8.0 billion in 2016 and $8.0 billion in 2015.

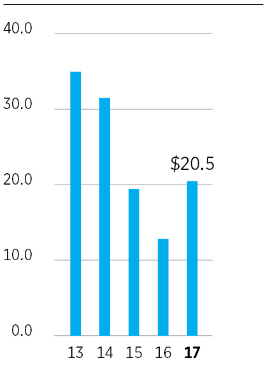
Debt and Capital Lease Obligations Total debt and capital lease obligations were $38.8 billion at December 31, 2017, down from $46.1 billion at year-end 2016.

The $7.3 billion decrease in total debt and capital lease obligations during 2017 was primarily due to a decrease in short-term obligations reflecting higher crude oil prices. The company completed a bond issuance of $4.0 billion in first quarter 2017 and repaid long-term notes totaling $6.2 billion that matured in February, November and December 2017. 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 $15.2 billion at December 31, 2017, compared with $19.8 billion at year-end 2016. Of these amounts, $10.0 billion and $9.0 billion were reclassified to long-term debt at the end of 2017 and 2016, respectively.

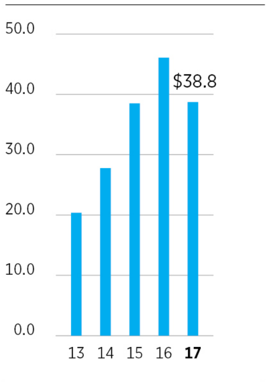
At year-end 2017, settlement of these obligations was not expected to require the use of working capital in 2018, as the company had the intent and the ability, as evidenced by committed credit facilities, to refinance them on a long-term basis.

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.

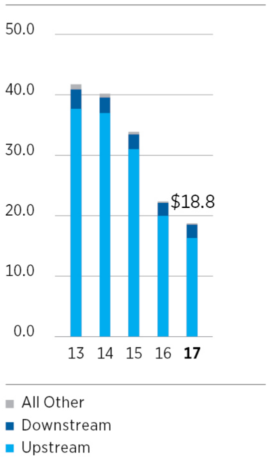
Cash provided by operating activities
Billions of dollars



Total debt at year-end
Billions of dollars

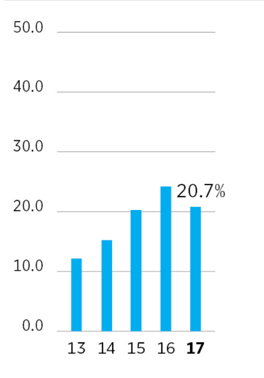


Capital & exploratory expenditures*
Billions of dollars



* 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 19, Short-Term Debt, on page 78.

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 2017 or 2016. 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 2017, 2016 and 2015 are as follows:

		2017			2016			2015	
Millions of dollars	U.S.	Int'l.	Total	U.S.	Int'l.	Total	U.S.	Int'l.	Total
Upstream	**$ 5,145**	**$ 11,243**	**$ 16,388**	$ 4,713	$ 15,403	$ 20,116	$ 7,582	$ 23,535	$ 31,117
Downstream	**1,656**	**534**	**2,190**	1,545	527	2,072	1,923	513	2,436
All Other	**239**	**4**	**243**	235	5	240	418	8	426
Total	**$ 7,040**	**$ 11,781**	**$ 18,821**	$ 6,493	$ 15,935	$ 22,428	$ 9,923	$ 24,056	$ 33,979
Total, Excluding Equity in Affiliates	**$ 6,295**	**$ 7,783**	**$ 14,078**	$ 5,456	$ 13,202	$ 18,658	$ 8,579	$ 22,003	$ 30,582

Total expenditures for 2017 were $18.8 billion, including $4.7 billion for the company’s share of equity-affiliate expenditures, which did not require cash outlays by the company. In 2016 and 2015, expenditures were $22.4 billion and $34.0 billion, respectively, including the company’s share of affiliates’ expenditures of $3.8 billion and $3.4 billion, respectively.

Of the $18.8 billion of expenditures in 2017, 87 percent, or $16.4 billion, related to upstream activities. Approximately 90 percent was expended for upstream operations in 2016 and 92 percent in 2015. International upstream accounted for 69 percent of the worldwide upstream investment in 2017, 77 percent in 2016 and 76 percent in 2015.

The company estimates that 2018 capital and exploratory expenditures will be $18.3 billion, including $5.5 billion of spending by affiliates. This planned reduction, compared to 2017 expenditures, reflects project completions, improved efficiencies, and investment high-grading, including the full funding of the company's advantaged Permian Basin position. Approximately 86 percent of the total, or $15.8 billion, is budgeted for exploration and production activities. Approximately $8.7 billion of planned upstream capital spending relates to base producing assets, including $3.3 billion for the Permian and $1.0 billion for other shale and tight rock investments. Approximately $5.5 billion of the upstream program is planned for major capital projects underway, including $3.7 billion associated with the Future Growth and Wellhead Pressure Management Project at the Tengiz field in Kazakhstan. Global exploration funding is expected to be about $1.1 billion. Remaining upstream spend is budgeted for early stage projects supporting potential future developments. The company will continue to monitor crude oil market conditions and expects to further restrict capital outlays should oil price conditions deteriorate.

Worldwide downstream spending in 2018 is estimated to be $2.2 billion, with $1.4 billion estimated for projects in the United States.

Investments in technology companies and other corporate businesses in 2018 are budgeted at $0.3 billion.

Noncontrolling Interests The company had noncontrolling interests of $1.2 billion at December 31, 2017 and December 31, 2016. Distributions to noncontrolling interests totaled $78 million and $63 million in 2017 and 2016, respectively.

Pension Obligations Information related to pension plan contributions is included on page 82 in Note 23, Employee Benefit Plans, under the heading “Cash Contributions and Benefit Payments.”

Financial Ratios

	At December 31		
	2017	2016	2015
Current Ratio	**1.0**	0.9	1.3
Interest Coverage Ratio	**10.7**	(2.6)	9.9
Debt Ratio	**20.7 %**	24.1 %	20.2 %

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 2017, the book value of inventory was lower than replacement costs, based on average acquisition costs during the year, by approximately $3.9 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 2017 was higher than 2016 and 2015 due to higher 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 was 20.7 percent at year-end 2017, compared with 24.1 percent and 20.2 percent at year-end 2016 and 2015, respectively.

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: 2018 – $1.4 billion; 2019 – $1.4 billion;

2020 – $1.0 billion; 2021 – $0.9 billion; 2022 – $0.5 billion; 2023 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 2017, $1.3 billion in 2016 and $1.9 billion in 2015.

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

	Payments Due by Period				
Millions of dollars	Total[1]	2018	2019-2020	2021-2022	After 2022
On Balance Sheet:[2]					
Short-Term Debt[3]	$ 5,194	$ 5,194	$ —	$ —	$ —
Long-Term Debt[3]	33,512	—	20,054	6,104	7,354
Noncancelable Capital Lease Obligations	226	26	35	23	142
Interest	4,078	786	1,173	850	1,269
Off Balance Sheet:					
Noncancelable Operating Lease Obligations	2,895	693	1,102	562	538
Throughput and Take-or-Pay Agreements[4]	5,277	655	1,285	866	2,471
Other Unconditional Purchase Obligations[4]	2,560	747	1,109	609	95

[1] Excludes contributions for pensions and other postretirement benefit plans. Information on employee benefit plans is contained in Note 23 beginning on page 82.
[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] $10.0 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 2019–2020 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	2018	2019-2020	2021-2022	After 2022
Guarantee of nonconsolidated affiliate or joint-venture obligations	$ 1,082	$ 114	$ 577	$ 214	$ 177

The company has two guarantees of equity affiliates totaling $1.08 billion. Of this amount, $712 million is associated with a financing arrangement with an equity affiliate. Over the approximate 4-year remaining term of this guarantee, the maximum amount will be reduced as payments are made by the affiliate. The remaining amount of $370 million is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 10-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 88 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 2017 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 2017.

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 2017 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, 2017 and 2016 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, 2017.

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 2017, 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 71, 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 71 in Note 17 under the heading "MTBE."

Ecuador Information related to Ecuador matters is included in Note 17 under the heading "Ecuador," beginning on page 71.

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		**2017**		2016		2015
Balance at January 1	**$**	**1,467**	$	1,578	$	1,683
Net Additions		**323**		260		365
Expenditures		**(361)**		(371)		(470)
Balance at December 31	**$**	**1,429**	$	1,467	$	1,578

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 2017 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 2017 environmental expenditures. Refer to Note 25 on page 88 for additional discussion of environmental remediation provisions and year-end reserves. Refer also to Note 26 on page 89 for additional discussion of the company's asset retirement obligations.

Suspended Wells Information related to suspended wells is included in Note 21, Accounting for Suspended Exploratory Wells, beginning on page 80.

Income Taxes Information related to income tax contingencies is included on pages 75 through 78 in Note 18 and page 87 in Note 25 under the heading "Income Taxes."

Other Contingencies Information related to other contingencies is included on page 89 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 and national, regional, and state legislation (e.g., California AB32, SB32 and AB398) and regulatory measures 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 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. In addition, legislation and regulations intended to address hydraulic fracturing also continue to evolve at the national, state and local levels. Refer to "Risk Factors" in Part I, Item 1A, on pages 19 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 or other pollutants into the environment; remediate and restore areas damaged by prior releases of 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 2017 at approximately $2.0 billion for its consolidated companies. Included in these expenditures were approximately $0.5 billion of environmental capital expenditures and $1.5 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 2018, total worldwide environmental capital expenditures are estimated at $0.5 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 2017, Chevron's UOP Depreciation, Depletion and Amortization (DD&A) for oil and gas properties was $14.8 billion, and proved developed reserves at the beginning of 2017 were 6.2 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 2017 would have increased by approximately $800 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 95, for the changes in proved reserve estimates for the three years ended December 31, 2017, and to Table VII, “Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Reserves” on page 101 for estimates of proved reserve values for each of the three years ended December 31, 2017.

This Oil and Gas Reserves commentary should be read in conjunction with the Properties, Plant and Equipment section of Note 1, beginning on page 57, 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 24 on page 87 and to the section on Properties, Plant and Equipment in Note 1, "Summary of Significant Accounting Policies," beginning on page 57.

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.

No individually material impairments of PP&E or Investments were recorded for the year 2017. 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. 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 2017 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 89 for additional discussions on asset retirement obligations.

Pension and Other Postretirement Benefit Plans Note 23, beginning on page 82, 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 84 in Note 23 under the relevant headings. Actual rates may vary significantly from estimates because of unanticipated changes in the world's financial markets.

For 2017, the company used an expected long-term rate of return of 6.75 percent and a discount rate for service costs of 4.2 percent and a discount rate for interest cost of 3.0 percent for U.S. pension plans. The actual return for 2017 was 15.7 percent. For the 10 years ending December 31, 2017, actual asset returns averaged 5.2 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 6.75 percent during each year.

Total pension expense for 2017 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 61 percent of companywide pension expense, would have reduced total pension plan expense for 2017 by approximately $79 million. A 1 percent increase in the discount rates for this same plan would have reduced pension expense for 2017 by approximately $305 million.

The aggregate funded status recognized at December 31, 2017, was a net liability of approximately $4.4 billion. An increase in the discount rate would decrease the pension obligation, thus changing the funded status of a plan. At December 31, 2017, the company used a discount rate of 3.5 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 $478 million, and would have decreased the plan’s underfunded status from approximately $2.0 billion to $1.5 billion.

For the company’s OPEB plans, expense for 2017 was $94 million, and the total liability, all unfunded at the end of 2017, was $2.8 billion. For the main U.S. OPEB plan, the company used a discount rate for service cost of 4.6 percent and a discount rate for interest cost of 3.4 percent to measure expense in 2017, and a 3.6 percent discount rate to measure the benefit obligations at December 31, 2017. Discount rate changes, similar to those used in the pension sensitivity analysis, resulted in an immaterial impact on 2017 OPEB expense and OPEB liabilities at the end of 2017. For information on the sensitivity of the health care cost-trend rate, refer to page 84 in Note 23 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 84 in Note 23 for a description of the method used to amortize the $5.5 billion of before-tax actuarial losses recorded by the company as of December 31, 2017, and an estimate of the costs to be recognized in expense during 2018. In addition, information related to company contributions is included on page 86 in Note 23 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 87. 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, 2017.

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 61 for information regarding new accounting standards.

Quarterly Results and Stock Market Data

Unaudited

	2017				2016			
Millions of dollars, except per-share amounts	4th Q	3rd Q	2nd Q	1st Q	4th Q	3rd Q	2nd Q	1st Q
Revenues and Other Income								
Sales and other operating revenues[1]	$ 36,381	$ 33,892	$ 32,877	$ 31,524	$ 30,142	$ 29,159	$ 27,844	$ 23,070
Income from equity affiliates	936	1,036	1,316	1,150	778	555	752	576
Other income	299	1,277	287	747	577	426	686	(93)
Total Revenues and Other Income	37,616	36,205	34,480	33,421	31,497	30,140	29,282	23,553
Costs and Other Deductions								
Purchased crude oil and products	21,158	18,776	18,325	17,506	16,976	15,842	15,278	11,225
Operating expenses	5,182	4,937	4,662	4,656	5,144	4,666	5,054	5,404
Selling, general and administrative expenses	1,349	1,238	991	870	1,544	1,109	1,033	998
Exploration expenses	356	239	125	144	191	258	214	370
Depreciation, depletion and amortization	4,735	5,109	5,311	4,194	4,203	4,130	6,721	4,403
Taxes other than on income[1]	3,182	3,213	3,065	2,871	2,869	2,962	2,973	2,864
Interest and debt expense	173	35	48	51	58	64	79	—
Total Costs and Other Deductions	36,135	33,547	32,527	30,292	30,985	29,031	31,352	25,264
Income (Loss) Before Income Tax Expense	1,481	2,658	1,953	3,129	512	1,109	(2,070)	(1,711)
Income Tax Expense (Benefit)	(1,637)	672	487	430	74	(192)	(607)	(1,004)
Net Income (Loss)	$ 3,118	$ 1,986	$ 1,466	$ 2,699	$ 438	$ 1,301	$ (1,463)	$ (707)
Less: Net income attributable to noncontrolling interests	7	34	16	17	23	18	7	18
Net Income (Loss) Attributable to Chevron Corporation	$ 3,111	$ 1,952	$ 1,450	$ 2,682	$ 415	$ 1,283	$ (1,470)	$ (725)
Per Share of Common Stock								
Net Income (Loss) Attributable to Chevron Corporation								
– Basic	$ 1.65	$ 1.03	$ 0.77	$ 1.43	$ 0.22	$ 0.68	$ (0.78)	$ (0.39)
– Diluted	$ 1.64	$ 1.03	$ 0.77	$ 1.41	$ 0.22	$ 0.68	$ (0.78)	$ (0.39)
Dividends	$ 1.08	$ 1.08	$ 1.08	$ 1.08	$ 1.08	$ 1.07	$ 1.07	$ 1.07
Common Stock Price Range – High[2]	$ 126.20	$ 118.33	$ 110.67	$ 119.00	$ 119.00	$ 107.58	$ 105.00	$ 97.91
– Low[2]	$ 112.57	$ 102.55	$ 102.55	$ 105.85	$ 99.61	$ 97.53	$ 92.43	$ 75.33
[1] Includes excise, value-added and similar taxes:	$ 1,874	$ 1,867	$ 1,771	$ 1,677	$ 1,697	$ 1,772	$ 1,784	$ 1,652

[2] Intraday price.

The company's common stock is listed on the New York Stock Exchange (trading symbol: CVX). As of February 12, 2018, stockholders of record numbered approximately 131,000. 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, 2017. 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, 2017.

The effectiveness of the company’s internal control over financial reporting as of December 31, 2017, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included herein.

/s/ MICHAEL K. WIRTH	/s/ PATRICIA E. YARRINGTON	/s/ JEANETTE L. OURADA
Michael K. Wirth	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 22, 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Chevron Corporation:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Chevron Corporation and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2017, including the related notes and financial statement schedule listed in the index appearing under Item 15(a)(2)(collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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 22, 2018

We have served as the Company’s auditor since 1935.

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

	Year ended December 31		
	2017	2016	2015
Revenues and Other Income			
Sales and other operating revenues*	**$ 134,674**	$ 110,215	$ 129,925
Income from equity affiliates	**4,438**	2,661	4,684
Other income	**2,610**	1,596	3,868
Total Revenues and Other Income	**141,722**	114,472	138,477
Costs and Other Deductions			
Purchased crude oil and products	**75,765**	59,321	69,751
Operating expenses	**19,437**	20,268	23,034
Selling, general and administrative expenses	**4,448**	4,684	4,443
Exploration expenses	**864**	1,033	3,340
Depreciation, depletion and amortization	**19,349**	19,457	21,037
Taxes other than on income*	**12,331**	11,668	12,030
Interest and debt expense	**307**	201	—
Total Costs and Other Deductions	**132,501**	116,632	133,635
Income (Loss) Before Income Tax Expense	**9,221**	(2,160)	4,842
Income Tax Expense (Benefit)	**(48)**	(1,729)	132
Net Income (Loss)	**9,269**	(431)	4,710
Less: Net income attributable to noncontrolling interests	**74**	66	123
Net Income (Loss) Attributable to Chevron Corporation	**$ 9,195**	$ (497)	$ 4,587
Per Share of Common Stock			
Net Income (Loss) Attributable to Chevron Corporation			
- Basic	**$ 4.88**	$ (0.27)	$ 2.46
- Diluted	**$ 4.85**	$ (0.27)	$ 2.45
* Includes excise, value-added and similar taxes.	**$ 7,189**	$ 6,905	$ 7,359

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income

Millions of dollars

	Year ended December 31		
	2017	2016	2015
Net Income (Loss)	**$ 9,269**	$ (431)	$ 4,710
Currency translation adjustment			
Unrealized net change arising during period	**57**	(22)	(44)
Unrealized holding (loss) gain on securities			
Net (loss) gain arising during period	**(3)**	27	(21)
Defined benefit plans			
Actuarial gain (loss)			
Amortization to net income of net actuarial loss and settlements	**817**	918	794
Actuarial (loss) gain arising during period	**(571)**	(315)	109
Prior service credits (cost)			
Amortization to net income of net prior service costs and curtailments	**(20)**	19	30
Prior service (costs) credits arising during period	**(1)**	345	6
Defined benefit plans sponsored by equity affiliates - benefit (cost)	**19**	(19)	30
Income (taxes) benefit on defined benefit plans	**(44)**	(505)	(336)
Total	**200**	443	633
Other Comprehensive Gain, Net of Tax	**254**	448	568
Comprehensive Income	**9,523**	17	5,278
Comprehensive income attributable to noncontrolling interests	**(74)**	(66)	(123)
Comprehensive Income (Loss) Attributable to Chevron Corporation	**$ 9,449**	$ (49)	$ 5,155

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Balance Sheet

Millions of dollars, except per-share amount

	At December 31	
	2017	2016
Assets		
Cash and cash equivalents	**$ 4,813**	$ 6,988
Marketable securities	**9**	13
Accounts and notes receivable (less allowance: 2017 - $490; 2016 - $373)	**15,353**	14,092
Inventories:		
Crude oil and petroleum products	**3,142**	2,720
Chemicals	**476**	455
Materials, supplies and other	**1,967**	2,244
Total inventories	**5,585**	5,419
Prepaid expenses and other current assets	**2,800**	3,107
Total Current Assets	**28,560**	29,619
Long-term receivables, net	**2,849**	2,485
Investments and advances	**32,497**	30,250
Properties, plant and equipment, at cost	**344,485**	336,077
Less: Accumulated depreciation, depletion and amortization	**166,773**	153,891
Properties, plant and equipment, net	**177,712**	182,186
Deferred charges and other assets	**7,017**	6,838
Goodwill	**4,531**	4,581
Assets held for sale	**640**	4,119
Total Assets	**$ 253,806**	$ 260,078
Liabilities and Equity		
Short-term debt (net of unamortized discount and debt issuance costs: $2 in 2017, $3 in 2016)	**$ 5,192**	$ 10,840
Accounts payable	**14,565**	13,986
Accrued liabilities	**5,267**	4,882
Federal and other taxes on income	**1,600**	1,050
Other taxes payable	**1,113**	1,027
Total Current Liabilities	**27,737**	31,785
Long-term debt (net of unamortized discount and debt issuance costs: $35 in 2017, $41 in 2016)	**33,477**	35,193
Capital lease obligations	**94**	93
Deferred credits and other noncurrent obligations	**21,106**	21,553
Noncurrent deferred income taxes	**14,652**	17,516
Noncurrent employee benefit plans	**7,421**	7,216
Total Liabilities*	**$ 104,487**	$ 113,356
Preferred stock (authorized 100,000,000 shares; $1.00 par value; none issued)	**—**	—
Common stock (authorized 6,000,000,000 shares; $0.75 par value; 2,442,676,580 shares issued at December 31, 2017 and 2016)	**1,832**	1,832
Capital in excess of par value	**16,848**	16,595
Retained earnings	**174,106**	173,046
Accumulated other comprehensive loss	**(3,589)**	(3,843)
Deferred compensation and benefit plan trust	**(240)**	(240)
Treasury stock, at cost (2017 - 537,974,695 shares; 2016 - 551,170,158 shares)	**(40,833)**	(41,834)
Total Chevron Corporation Stockholders' Equity	**148,124**	145,556
Noncontrolling interests	**1,195**	1,166
Total Equity	**149,319**	146,722
Total Liabilities and Equity	**$ 253,806**	$ 260,078

See accompanying Notes to the Consolidated Financial Statements.

* Refer to Note 25, "Other Contingencies and Commitments" beginning on page 87.

Consolidated Statement of Cash Flows
Millions of dollars

	Year ended December 31		
	2017	2016	2015
Operating Activities			
Net Income (Loss)	**$ 9,269**	$ (431)	$ 4,710
Adjustments			
Depreciation, depletion and amortization	**19,349**	19,457	21,037
Dry hole expense	**198**	489	2,309
Distributions less than income from equity affiliates	**(2,214)**	(1,227)	(760)
Net before-tax gains on asset retirements and sales	**(2,195)**	(1,149)	(3,215)
Net foreign currency effects	**131**	186	(82)
Deferred income tax provision	**(3,203)**	(3,835)	(1,861)
Net decrease (increase) in operating working capital	**476**	(550)	(1,979)
Increase in long-term receivables	**(368)**	(131)	(59)
(Increase) decrease in other deferred charges	**(199)**	235	25
Cash contributions to employee pension plans	**(980)**	(870)	(868)
Other	**251**	672	199
Net Cash Provided by Operating Activities	**20,515**	12,846	19,456
Investing Activities			
Capital expenditures	**(13,404)**	(18,109)	(29,504)
Proceeds and deposits related to asset sales	**5,247**	2,777	5,739
Net maturities of time deposits	**—**	—	8
Net sales of marketable securities	**4**	297	122
Net borrowing of loans by equity affiliates	**(16)**	(2,034)	(217)
Net (purchases) sales of other short-term investments	**(32)**	217	44
Net Cash Used for Investing Activities	**(8,201)**	(16,852)	(23,808)
Financing Activities			
Net (repayments) borrowings of short-term obligations	**(5,142)**	2,130	(335)
Proceeds from issuances of long-term debt	**3,991**	6,924	11,091
Repayments of long-term debt and other financing obligations	**(6,310)**	(1,584)	(32)
Cash dividends - common stock	**(8,132)**	(8,032)	(7,992)
Distributions to noncontrolling interests	**(78)**	(63)	(128)
Net sales of treasury shares	**1,117**	650	211
Net Cash (Used for) Provided by Financing Activities	**(14,554)**	25	2,815
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**65**	(53)	(226)
Net Change in Cash and Cash Equivalents	**(2,175)**	(4,034)	(1,763)
Cash and Cash Equivalents at January 1	**6,988**	11,022	12,785
Cash and Cash Equivalents at December 31	**$ 4,813**	$ 6,988	$ 11,022

See accompanying Notes to the Consolidated Financial Statements.

Consolidated Statement of Equity

Shares in thousands; amounts in millions of dollars

	2017		2016		2015	
	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		**$ 16,595**		$ 16,330		$ 16,041
Treasury stock transactions		**253**		265		289
Balance at December 31		**$ 16,848**		$ 16,595		$ 16,330
Retained Earnings						
Balance at January 1		**$ 173,046**		$ 181,578		$ 184,987
Net income (loss) attributable to Chevron Corporation		**9,195**		(497)		4,587
Cash dividends on common stock		**(8,132)**		(8,032)		(7,992)
Stock dividends		**(3)**		(3)		(3)
Tax (charge) benefit from dividends paid on unallocated ESOP shares and other		**—**		—		(1)
Balance at December 31		**$ 174,106**		$ 173,046		$ 181,578
Accumulated Other Comprehensive Loss						
Currency translation adjustment						
Balance at January 1		**$ (162)**		$ (140)		$ (96)
Change during year		**57**		(22)		(44)
Balance at December 31		**$ (105)**		$ (162)		$ (140)
Unrealized net holding (loss) gain on securities						
Balance at January 1		**$ (2)**		$ (29)		$ (8)
Change during year		**(3)**		27		(21)
Balance at December 31		**$ (5)**		$ (2)		$ (29)
Net derivatives (loss) gain on hedge transactions						
Balance at January 1		**$ (2)**		$ (2)		$ (2)
Change during year		**—**		—		—
Balance at December 31		**$ (2)**		$ (2)		$ (2)
Pension and other postretirement benefit plans						
Balance at January 1		**$ (3,677)**		$ (4,120)		$ (4,753)
Change during year		**200**		443		633
Balance at December 31		**$ (3,477)**		$ (3,677)		$ (4,120)
Balance at December 31		**$ (3,589)**		$ (3,843)		$ (4,291)
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	**551,170**	**$ (41,834)**	559,863	$ (42,493)	563,028	$ (42,733)
Purchases	**10**	**(1)**	20	(2)	15	(2)
Issuances - mainly employee benefit plans	**(13,205)**	**1,002**	(8,713)	661	(3,180)	242
Balance at December 31	**537,975**	**$ (40,833)**	551,170	$ (41,834)	559,863	$ (42,493)
Total Chevron Corporation Stockholders' Equity at December 31		**$ 148,124**		$ 145,556		$ 152,716
Noncontrolling Interests		**$ 1,195**		$ 1,166		$ 1,170
Total Equity		**$ 149,319**		$ 146,722		$ 153,886

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 are primarily stated at net realizable value.

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 21, beginning on page 80, 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 64, 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 89, 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. Impairments 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 annually at December 31, or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount.

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

Liabilities related to future remediation costs are recorded when environmental assessments or cleanups or both are probable and the costs can be reasonably estimated. For 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 89, 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 52. 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 in which an employee becomes eligible to retain the award at retirement. The company's Long-Term Incentive Plan (LTIP) awards include stock options and stock appreciation rights, which have graded vesting provisions by which one-third of each award vests on each of the first, second and third anniversaries of the date of grant. In addition, performance shares granted under the company's LTIP will vest at the end of the three-year performance period. For awards granted under the company's LTIP beginning in 2017, stock options and stock appreciation rights 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 unit awards have cliff vesting by which the total award will vest on January 31 on or after the fifth anniversary of the grant date, subject to adjustment upon termination pursuant to the satisfaction of certain criteria. 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, 2017, are reflected in the table below.

	Year Ended December 31, 2017[1]				
	Currency Translation Adjustments	Unrealized Holding Gains (Losses) on Securities	Derivatives	Defined Benefit Plans	Total
Balance at January 1	$ (162)	$ (2)	$ (2)	$ (3,677)	$ (3,843)
Components of Other Comprehensive Income (Loss):					
Before Reclassifications	57	(3)	—	(310)	(256)
Reclassifications[2]	—	—	—	510	510
Net Other Comprehensive Income (Loss)	57	(3)	—	200	254
Balance at December 31	$ (105)	$ (5)	$ (2)	$ (3,477)	$ (3,589)

[1] All amounts are net of tax.

[2] Refer to Note 23 beginning on page 82, for reclassified components totaling $796 that are included in employee benefit costs for the year ending December 31, 2017. Related income taxes for the same period, totaling $286, 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 2017, 2016 and 2015 is as follows:

		2017		2016		2015
Balance at January 1	**$**	**1,166**	$	1,170	$	1,163
Net income		**74**		66		123
Distributions to noncontrolling interests		**(78)**		(63)		(128)
Other changes, net		**33**		(7)		12
Balance at December 31	**$**	**1,195**	$	1,166	$	1,170

Note 4

Information Relating to the Consolidated Statement of Cash Flows

	Year ended December 31					
		2017		2016		2015
Net decrease (increase) in operating working capital was composed of the following:						
(Increase) decrease in accounts and notes receivable	**$**	**(915)**	$	(2,121)	$	3,631
(Increase) decrease in inventories		**(267)**		603		85
Decrease in prepaid expenses and other current assets		**252**		439		713
Increase (decrease) in accounts payable and accrued liabilities		**875**		533		(5,769)
Increase (decrease) in income and other taxes payable		**531**		(4)		(639)
Net decrease (increase) in operating working capital	**$**	**476**	$	(550)	$	(1,979)
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)	**$**	**265**	$	158	$	—
Income taxes		**3,132**		1,935		4,645
Net sales of marketable securities consisted of the following gross amounts:						
Marketable securities purchased	**$**	**(3)**	$	(9)	$	(6)
Marketable securities sold		**7**		306		128
Net sales of marketable securities	**$**	**4**	$	297	$	122
Net maturities of time deposits consisted of the following gross amounts:						
Investments in time deposits	**$**	**—**	$	—	$	—
Maturities of time deposits		**—**		—		8
Net maturities of time deposits	**$**	**—**	$	—	$	8
Net (borrowing) repayment of loans by equity affiliates:						
Borrowing of loans by equity affiliates	**$**	**(142)**	$	(2,341)	$	(223)
Repayment of loans by equity affiliates		**126**		307		6
Net (borrowing) repayment of loans by equity affiliates	**$**	**(16)**	$	(2,034)	$	(217)
Net (purchases) sales of other short-term investments:						
Purchases of other short-term investments	**$**	**(41)**	$	(1)	$	(75)
Sales of other short-term investments		**9**		218		119
Net (purchases) sales of other short-term investments	**$**	**(32)**	$	217	$	44
Net borrowings (repayments) of short-term obligations consisted of the following gross and net amounts:						
Proceeds from issuances of short-term obligations	**$**	**5,051**	$	14,778	$	13,805
Repayments of short-term obligations		**(8,820)**		(12,558)		(16,379)
Net (repayments) borrowings of short-term obligations with three months or less maturity		**(1,373)**		(90)		2,239
Net (repayments) borrowings of short-term obligations	**$**	**(5,142)**	$	2,130	$	(335)

A loan to Tengizchevroil LLP for the development of the Future Growth and Wellhead Pressure Management Project represents the majority of "Net borrowing of loans by equity affiliates" in 2016.

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 $1, $2 and $2 in 2017, 2016 and 2015, respectively. No purchases were made under the company's share repurchase program in 2017, 2016, or 2015.

In 2017, 2016 and 2015, "Net (purchases) sales 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. In 2017, an approximate $400 increase in "Deferred credits and other noncurrent obligations" and a corresponding increase to "Properties, plant and equipment, at cost" were considered non-cash transactions and excluded from "Net increase in operating working capital" and "Capital expenditures." The amount is related to upstream operating agreements outside of the United States.

Refer also to Note 26, on page 89, 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, 2017.

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		
	2017	2016	2015
Additions to properties, plant and equipment *	$ **13,222**	$ 17,742	$ 28,213
Additions to investments	**25**	55	555
Current-year dry hole expenditures	**157**	313	736
Payments for other liabilities and assets, net	**—**	(1)	—
Capital expenditures	**13,404**	18,109	29,504
Expensed exploration expenditures	**666**	544	1,031
Assets acquired through capital lease obligations and other financing obligations	**8**	5	47
Capital and exploratory expenditures, excluding equity affiliates	**14,078**	18,658	30,582
Company's share of expenditures by equity affiliates	**4,743**	3,770	3,397
Capital and exploratory expenditures, including equity affiliates	**$ 18,821**	$ 22,428	$ 33,979

* Excludes noncash additions of $1,183 in 2017, $56 in 2016 and $1,362 in 2015.

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 completed its accounting policy and system enhancements necessary to meet the standard's requirements. The company does not expect the implementation of the standard to have a material effect on its consolidated financial statements.

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's implementation efforts are focused on accounting policy and disclosure updates and system enhancements necessary to meet the standard's requirements. The company is evaluating the effect of the standard on 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.

Other Income - Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20) In March 2017, the FASB issued ASU 2017-05, which becomes effective for the company January 1, 2018. The standard provides clarification regarding the guidance on accounting for the derecognition of nonfinancial assets. The company does not expect the implementation of the standard to have a material effect on its consolidated financial statements.

Compensation - Retirement Benefits (Topic 715) In March 2017, the FASB issued ASU 2017-07, which becomes effective for the company January 1, 2018. The standard requires the disaggregation of the service cost component from the other components of net periodic benefit cost and allows only the service cost component of net benefit cost to be eligible for capitalization. The company does not expect the implementation of the standard to have a material effect on its consolidated financial statements.

Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued ASU 2016-15, which becomes effective for the company January 1, 2018 on a retrospective basis. The standard provides clarification on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. The company does not expect the adoption of this ASU to have a material impact on its Consolidated Statement of Cash Flows.

Statement of Cash Flows (Topic 230) Restricted Cash In November 2016, the FASB issued ASU 2016-18, which becomes effective for the company January 1, 2018 on a retrospective basis. The standard requires an entity to explain the changes in the total of cash, cash equivalents, restricted cash and restricted cash equivalents on the statement of cash flows and to provide a reconciliation to the balance sheet when the cash, cash equivalents, restricted cash and restricted cash equivalents are not separately presented or are presented in more than one line item on the balance sheet. Upon adoption, the company's restricted cash balances will be included in the beginning and ending balances on the Consolidated Statement of Cash Flows.

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	
	2017	2016
Upstream	**$ 678**	$ 676
Downstream	**99**	99
All Other	**—**	—
Total	**777**	775
Less: Accumulated amortization	**515**	383
Net capitalized leased assets	**$ 262**	$ 392

Rental expenses incurred for operating leases during 2017, 2016 and 2015 were as follows:

	Year ended December 31		
	2017	2016	2015
Minimum rentals	**$ 726**	$ 943	$ 1,041
Contingent rentals	**1**	2	2
Total	**727**	945	1,043
Less: Sublease rental income	**6**	7	9
Net rental expense	**$ 721**	$ 938	$ 1,034

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, 2017, 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 2018	$ 693	$ 26
2019	628	22
2020	474	13
2021	339	12
2022	223	11
Thereafter	538	142
Total	$ 2,895	$ 226
Less: Amounts representing interest and executory costs		$ (117)
Net present values		109
Less: Capital lease obligations included in short-term debt		(15)
Long-term capital lease obligations		$ 94

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		
	2017	2016	2015
Sales and other operating revenues	**$ 104,054**	$ 83,715	$ 97,766
Total costs and other deductions	**103,904**	87,429	101,565
Net income (loss) attributable to CUSA	**4,842**	(1,177)	(1,054)

	2017	2016
Current assets	**$ 12,163**	$ 11,266
Other assets	**54,994**	55,722
Current liabilities	**17,379**	16,660
Other liabilities	**12,541**	21,701
Total CUSA net equity	**$ 37,237**	$ 28,627
Memo: Total debt	**$ 3,056**	$ 9,418

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 70, for a discussion of TCO operations. Summarized financial information for 100 percent of TCO is presented in the table below:

	Year ended December 31		
	2017	2016	2015
Sales and other operating revenues	**$ 13,363**	$ 10,460	$ 12,811
Costs and other deductions	**6,507**	6,822	7,257
Net income attributable to TCO	**4,841**	2,563	3,897

	At December 31	
	2017	2016
Current assets	**$ 4,239**	$ 7,001
Other assets	**26,411**	20,476

Current liabilities		**2,517**		2,841
Other liabilities		**6,266**		6,210
Total TCO net equity	**$**	**21,867**	$	18,426

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 70, for a discussion of CPChem operations. Summarized financial information for 100 percent of CPChem is presented in the table below:

	Year ended December 31		
	2017	2016	2015
Sales and other operating revenues	**$ 9,063**	$ 8,455	$ 9,248
Costs and other deductions	**8,126**	7,017	7,136
Net income attributable to CPChem	**1,446**	1,687	2,651

	At December 31	
	2017	2016
Current assets	**$ 2,944**	$ 2,695
Other assets	**13,823**	12,770
Current liabilities	**1,439**	1,418
Other liabilities	**2,932**	2,569
Total CPChem net equity	**$ 12,396**	$ 11,478

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, 2017, and December 31, 2016.

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, 2017.

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

Properties, Plant and Equipment The company did not have any individually material impairments in 2017. The company reported impairments for certain oil and gas properties during 2016 primarily due to reservoir performance and lower crude oil prices. The impairments in 2016 were primarily in Brazil and the United States.

Investments and Advances The company did not have any individually material impairments of investments and advances in 2017 or 2016.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

	At December 31, 2017				At December 31, 2016			
	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
Marketable securities	**$ 9**	**$ 9**	**$ —**	**$ —**	$ 13	$ 13	$ —	$ —
Derivatives	**22**	**—**	**22**	**—**	32	15	17	—
Total assets at fair value	**$ 31**	**$ 9**	**$ 22**	**$ —**	$ 45	$ 28	$ 17	$ —
Derivatives	**124**	**78**	**46**	**—**	109	78	31	—
Total liabilities at fair value	**$ 124**	**$ 78**	**$ 46**	**$ —**	$ 109	$ 78	$ 31	$ —

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 2017		Total	Level 1	Level 2	Level 3	Year 2016
Properties, plant and equipment, net (held and used)	**$ 603**	**$ —**	**$ —**	**$ 603**	**$ 658**		$ 582	$ —	$ 15	$ 567	$ 2,507
Properties, plant and equipment, net (held for sale)	**1,378**	**—**	**1,378**	**—**	**363**		891	—	888	3	679
Investments and advances	**28**	**—**	**1**	**27**	**26**		26	—	20	6	234
Total nonrecurring assets at fair value	**$ 2,009**	**$ —**	**$ 1,379**	**$ 630**	**$ 1,047**		$ 1,499	$ —	$ 923	$ 576	$ 3,420

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 $4,813 and $6,988 at December 31, 2017, and December 31, 2016, 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, 2017.

"Cash and cash equivalents” do not include investments with a carrying/fair value of $1,130 and $1,426 at December 31, 2017, and December 31, 2016, respectively. At December 31, 2017, these investments are classified as Level 1 and include restricted funds related to certain upstream abandonment activities, tax payments 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 $23,477 and $26,193 at December 31, 2017, and December 31, 2016, respectively, had estimated fair values of $23,943 and $26,627, respectively. Long-term debt primarily includes corporate issued bonds. The fair value of corporate bonds is $23,245 and classified as Level 1. The fair value of other long-term debt is $698 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, 2017 and 2016, 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, 2017, December 31, 2016, and December 31, 2015, and their classification on the Consolidated Balance Sheet and Consolidated Statement of Income are on the next page:

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

		At December 31	
Type of Contract	Balance Sheet Classification	**2017**	2016
Commodity	Accounts and notes receivable, net	**$ 22**	$ 30
Commodity	Long-term receivables, net	**—**	2
Total assets at fair value		**$ 22**	$ 32
Commodity	Accounts payable	**$ 122**	$ 99
Commodity	Deferred credits and other noncurrent obligations	**2**	10
Total liabilities at fair value		**$ 124**	$ 109

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	**2017**	2016	2015
Commodity	Sales and other operating revenues	**$ (105)**	$ (269)	$ 277
Commodity	Purchased crude oil and products	**(9)**	(31)	30
Commodity	Other income	**(2)**	—	(3)
		$ (116)	$ (300)	$ 304

The table below represents gross and net derivative assets and liabilities subject to netting agreements on the Consolidated Balance Sheet at December 31, 2017 and December 31, 2016.

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

At December 31, 2017	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset	Net Amounts
Derivative Assets	$ 1,169	$ 1,147	$ 22	$ —	$ 22
Derivative Liabilities	$ 1,271	$ 1,147	$ 124	$ —	$ 124
At December 31, 2016					
Derivative Assets	$ 1,052	$ 1,020	$ 32	$ —	$ 32
Derivative Liabilities	$ 1,129	$ 1,020	$ 109	$ —	$ 109

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, 2017, the company classified $640 of net properties, plant and equipment as “Assets held for sale” on the Consolidated Balance Sheet. These assets are primarily associated with downstream and upstream operations that are anticipated to be sold in the next 12 months. The revenues and earnings contributions of these assets in 2017 were not material.

Note 13
Equity

Retained earnings at December 31, 2017 and 2016, included approximately $18,473 and $16,479, respectively, for the company's share of undistributed earnings of equity affiliates.

At December 31, 2017, about 82 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, 800,468 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 22, "Stock Options and Other Share-Based Compensation," beginning on page 81). The table below sets forth the computation of basic and diluted EPS:

	Year ended December 31		
	2017	2016	2015
Basic EPS Calculation			
Earnings available to common stockholders - Basic[1]	**$ 9,195**	$ (497)	$ 4,587
Weighted-average number of common shares outstanding[2]	**1,882**	1,872	1,867
Add: Deferred awards held as stock units	**1**	1	1
Total weighted-average number of common shares outstanding	**1,883**	1,873	1,868
Earnings per share of common stock - Basic	**$ 4.88**	$ (0.27)	$ 2.46
Diluted EPS Calculation			
Earnings available to common stockholders - Diluted[1]	**$ 9,195**	$ (497)	$ 4,587
Weighted-average number of common shares outstanding[2]	**1,882**	1,872	1,867
Add: Deferred awards held as stock units	**1**	1	1
Add: Dilutive effect of employee stock-based awards	**15**	—	7
Total weighted-average number of common shares outstanding	**1,898**	1,873	1,875
Earnings per share of common stock - Diluted	**$ 4.85**	$ (0.27)	$ 2.45

[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 following table:

	Year ended December 31		
	2017	2016	2015
Upstream			
United States	**$ 3,640**	$ (2,054)	$ (4,055)
International	**4,510**	(483)	2,094
Total Upstream	**8,150**	(2,537)	(1,961)
Downstream			
United States	**2,938**	1,307	3,182
International	**2,276**	2,128	4,419
Total Downstream	**5,214**	3,435	7,601
Total Segment Earnings	**13,364**	898	5,640
All Other			
Interest expense	**(264)**	(168)	—
Interest income	**60**	58	65
Other	**(3,965)**	(1,285)	(1,118)
Net Income (Loss) Attributable to Chevron Corporation	**$ 9,195**	$ (497)	$ 4,587

Segment Assets Segment assets do not include intercompany investments or receivables. Assets at year-end 2017 and 2016 are as follows:

	At December 31	
	2017	2016
Upstream		
United States	**$ 40,770**	$ 42,596
International	**159,612**	164,068
Goodwill	**4,531**	4,581
Total Upstream	**204,913**	211,245
Downstream		
United States	**23,202**	22,264
International	**17,434**	15,816
Total Downstream	**40,636**	38,080
Total Segment Assets	**245,549**	249,325
All Other		
United States	**4,938**	4,852
International	**3,319**	5,901
Total All Other	**8,257**	10,753
Total Assets – United States	**68,910**	69,712
Total Assets – International	**180,365**	185,785
Goodwill	**4,531**	4,581
Total Assets	**$ 253,806**	$ 260,078

Segment Sales and Other Operating Revenues Operating segment sales and other operating revenues, including internal transfers, for the years 2017, 2016 and 2015, 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*		
	2017	2016	2015
Upstream			
United States	**$ 3,901**	$ 3,148	$ 4,117
Intersegment	**9,341**	7,217	8,631
Total United States	**13,242**	10,365	12,748
International	**17,209**	13,262	15,587
Intersegment	**11,471**	9,518	11,492
Total International	**28,680**	22,780	27,079
Total Upstream	**41,922**	33,145	39,827
Downstream			
United States	**48,728**	40,366	48,420
Excise and similar taxes	**4,398**	4,335	4,426
Intersegment	**14**	16	26
Total United States	**53,140**	44,717	52,872
International	**57,438**	46,388	54,296
Excise and similar taxes	**2,791**	2,570	2,933
Intersegment	**1,166**	1,068	1,528
Total International	**61,395**	50,026	58,757
Total Downstream	**114,535**	94,743	111,629
All Other			
United States	**208**	145	141
Intersegment	**814**	960	1,372
Total United States	**1,022**	1,105	1,513
International	**1**	1	5
Intersegment	**25**	36	37
Total International	**26**	37	42
Total All Other	**1,048**	1,142	1,555
Segment Sales and Other Operating Revenues			
United States	**67,404**	56,187	67,133
International	**90,101**	72,843	85,878
Total Segment Sales and Other Operating Revenues	**157,505**	129,030	153,011
Elimination of intersegment sales	**(22,831)**	(18,815)	(23,086)
Total Sales and Other Operating Revenues	**$ 134,674**	$ 110,215	$ 129,925

* Other than the United States, no other country accounted for 10 percent or more of the company's Sales and Other Operating Revenues.

Segment Income Taxes Segment income tax expense for the years 2017, 2016 and 2015 is as follows:

	Year ended December 31		
	2017	2016	2015
Upstream			
United States	**$ (3,538)**	$ (1,172)	$ (2,041)
International	**2,249**	166	1,214
Total Upstream	**(1,289)**	(1,006)	(827)
Downstream			
United States	**(419)**	503	1,320
International	**650**	484	1,313
Total Downstream	**231**	987	2,633
All Other	**1,010**	(1,710)	(1,674)

Total Income Tax Expense (Benefit)	**$**	**(48)**	$ (1,729)	$ 132

Other Segment Information Additional information for the segmentation of major equity affiliates is contained in Note 16, on page 70. Information related to properties, plant and equipment by segment is contained in Note 24, on page 87.

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		
	2017	2016	**2017**	2016	2015
Upstream					
Tengizchevroil	**$ 13,121**	$ 11,414	**$ 2,581**	$ 1,380	$ 1,939
Petropiar	**1,152**	977	**175**	326	180
Caspian Pipeline Consortium	**1,151**	1,245	**155**	145	162
Petroboscan	**1,080**	982	**154**	(133)	219
Angola LNG Limited	**2,625**	2,744	**31**	(282)	(417)
Other	**1,714**	1,791	**100**	(193)	135
Total Upstream	**20,843**	19,153	**3,196**	1,243	2,218
Downstream					
GS Caltex Corporation	**3,826**	3,767	**290**	373	824
Chevron Phillips Chemical Company LLC	**6,200**	5,767	**723**	840	1,367
Caltex Australia Ltd.	**—**	—	**—**	—	92
Other	**1,251**	1,118	**230**	209	186
Total Downstream	**11,277**	10,652	**1,243**	1,422	2,469
All Other					
Other	**(15)**	(16)	**(1)**	(4)	(3)
Total equity method	**32,105**	$ 29,789	**$ 4,438**	$ 2,661	$ 4,684
Other at or below cost	**392**	461			
Total investments and advances	**$ 32,497**	$ 30,250			
Total United States	**$ 7,582**	$ 7,258	**$ 788**	$ 802	$ 1,342
Total International	**$ 24,915**	$ 22,992	**$ 3,650**	$ 1,859	$ 3,342

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, 2017, the company's carrying value of its investment in TCO was about $130 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. Included in the investment is a loan to TCO to fund the development of the Future Growth and Wellhead Pressure Management Project with a balance of $2,060, including accrued interest. See Note 8, on page 63, 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, 2017, the company's carrying value of its investment in Petropiar was approximately $145 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 $1,151, which includes long-term loans of $727 at year-end 2017. 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, 2017, the company's carrying value of its investment in Petroboscan was approximately $105 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 $686 at year-end 2017.

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 $8,165, $5,786 and $4,850 with affiliated companies for 2017, 2016 and 2015, respectively. "Purchased crude oil and products" includes $4,800, $3,468 and $4,240 with affiliated companies for 2017, 2016 and 2015, respectively.

"Accounts and notes receivable" on the Consolidated Balance Sheet includes $1,141 and $676 due from affiliated companies at December 31, 2017 and 2016, respectively. "Accounts payable" includes $498 and $383 due to affiliated companies at December 31, 2017 and 2016, 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 $3,853, $3,535 and $410 at December 31, 2017, 2016 and 2015, respectively.

		Affiliates			Chevron Share	
Year ended December 31	**2017**	2016	2015	**2017**	2016	2015
Total revenues	**$ 70,744**	$ 59,253	$ 71,389	**$ 33,460**	$ 27,787	$ 33,492
Income before income tax expense	**13,487**	6,587	13,129	**5,712**	3,670	6,279
Net income attributable to affiliates	**10,751**	5,127	10,649	**4,468**	2,876	4,691
At December 31						
Current assets	**$ 33,883**	$ 33,406	$ 27,162	**$ 13,568**	$ 13,743	$ 10,657
Noncurrent assets	**82,261**	75,258	71,650	**32,643**	28,854	26,607
Current liabilities	**26,873**	24,793	20,559	**10,201**	8,996	7,351
Noncurrent liabilities	**21,447**	22,671	18,560	**4,224**	4,255	3,909
Total affiliates' net equity	**$ 67,824**	$ 61,200	$ 59,693	**$ 31,786**	$ 29,346	$ 26,004

Note 17

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 eight 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.

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 November 29, 2017, the Superior Court of Justice issued a decision dismissing the Lago Agrio plaintiffs’ recognition and enforcement proceeding based on jurisdictional grounds.

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. On February 24, 2017, the public prosecutor in Argentina issued a supplemental opinion reaffirming its previous recommendations. On November 1, 2017, the National Court, First Instance, of Argentina issued a decision dismissing the Lago Agrio plaintiffs' recognition and enforcement proceeding based on jurisdictional grounds. On November 2, 2017, the Lago Agrio plaintiffs appealed this decision to the Federal Civil Court of Appeals.

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 January 25, 2012, the Tribunal issued its First Interim Measures Award 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 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. 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. On July 18, 2017, the Appeals Court of the Hague denied the Republic's appeal. On October 18, 2017, the Republic appealed the decision of the Appeals Court of the Hague to the Supreme Court of the Netherlands.

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 sought relief that included 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. 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. On March 27, 2017, two of the defendants filed a petition for a Writ of Certiorari to the United States Supreme Court. On June 19, 2017, the United States Supreme Court denied the defendants' petition for a Writ of Certiorari.

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 18
Taxes

Income Taxes

	Year ended December 31		
	2017	2016	2015
Income tax expense (benefit)			
U.S. federal			
Current	**$ (382)**	$ (623)	$ (817)
Deferred	**(2,561)**	(1,558)	(580)
State and local			
Current	**(97)**	(15)	(187)
Deferred	**66**	(121)	(109)
Total United States	**(2,974)**	(2,317)	(1,693)
International			
Current	**3,634**	2,744	2,997
Deferred	**(708)**	(2,156)	(1,172)
Total International	**2,926**	588	1,825
Total income tax expense (benefit)	**$ (48)**	$ (1,729)	$ 132

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:

	2017	2016	2015
Income (loss) before income taxes			
United States	**$ (441)**	$ (4,317)	$ (2,877)
International	**9,662**	2,157	7,719
Total income (loss) before income taxes	**9,221**	(2,160)	4,842
Theoretical tax (at U.S. statutory rate of 35%)	**3,227**	(756)	1,695
Effect of U.S. tax reform	**(2,020)**	—	—
Equity affiliate accounting effect	**(1,373)**	(704)	(1,286)
Effect of income taxes from international operations*	**(130)**	608	72
State and local taxes on income, net of U.S. federal income tax benefit	**39**	(44)	(74)
Prior year tax adjustments, claims and settlements	**(39)**	(349)	84
Tax credits	**(199)**	(188)	(35)
Other U.S.*	**447**	(296)	(324)
Total income tax expense (benefit)	**$ (48)**	$ (1,729)	$ 132
Effective income tax rate	**(0.5)%**	80.0%	2.7%

* Includes one-time tax costs (benefits) associated with changes in uncertain tax positions and valuation allowances.

The 2017 decline in income tax benefit of $1,681, from a benefit of $1,729 in 2016 to a benefit of $48 in 2017, is a result of the year-over-year increase in total income before income tax expense, which is primarily due to effects of higher crude oil prices and gains on asset sales primarily in Indonesia and Canada. In addition, the tax benefit for the year includes a provisional benefit of $2,020 from U.S. tax reform, which primarily reflects the remeasurement of U.S. deferred tax assets and liabilities. The company's effective tax rate changed from 80 percent in 2016 to (0.5) percent in 2017. 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 and the 2017 impact of U.S. tax reform.

As noted above, U.S. tax reform resulted in the remeasurement of U.S. deferred tax assets and liabilities. The final impact will not be known until the actual 2017 U.S. tax return is submitted in 2018, and this may result in a change to the provisional amounts that have been recognized.

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

		At December 31		
		2017		2016
Deferred tax liabilities				
Properties, plant and equipment	**$**	**19,869**	$	25,180
Investments and other		**4,796**		5,222
Total deferred tax liabilities		**24,665**		30,402
Deferred tax assets				
Foreign tax credits		**(11,872)**		(10,976)
Asset retirement obligations/environmental reserves		**(5,511)**		(6,251)
Employee benefits		**(3,129)**		(4,392)
Deferred credits		**(1,769)**		(1,950)
Tax loss carryforwards		**(5,463)**		(6,030)
Other accrued liabilities		**(842)**		(510)
Inventory		**(336)**		(374)
Miscellaneous		**(2,415)**		(3,121)
Total deferred tax assets		**(31,337)**		(33,604)
Deferred tax assets valuation allowance		**16,574**		16,069
Total deferred taxes, net	**$**	**9,902**	$	12,867

Deferred tax liabilities at the end of 2017 decreased by approximately $5,700 from year-end 2016. The decrease was primarily related to property, plant and equipment temporary differences mainly due to the change in the enacted U.S. tax rate.

Deferred tax assets decreased by approximately $2,300 in 2017. Decreases were mainly due to the change in the enacted U.S. tax rate and primarily impacted asset retirement obligations, employee benefits and tax loss carry forwards. The decrease was partially reduced by an increase in foreign tax credits arising from earnings in high-tax rate international jurisdictions, which was substantially offset by valuation allowances.

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 2017, the company had tax loss carryforwards of approximately $16,102 and tax credit carryforwards of approximately $1,379, 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 2018 through 2034. U.S. foreign tax credit carryforwards of $11,872 will expire between 2018 and 2027.

At December 31, 2017 and 2016, deferred taxes were classified on the Consolidated Balance Sheet as follows:

		At December 31		
		2017		2016
Deferred charges and other assets	**$**	**(4,750)**	$	(4,649)
Noncurrent deferred income taxes		**14,652**		17,516
Total deferred income taxes, net	**$**	**9,902**	$	12,867

Enactment of U.S. tax reform imposed a one-time U.S. federal tax on the deemed repatriation of unremitted earnings indefinitely reinvested abroad, which did not have a material impact on the company's financial results. The indefinite reinvestment assertion continues to apply for the purpose of determining deferred tax liabilities for U.S. state and foreign withholding tax purposes.

U.S. state and foreign withholding 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 $57,300 at December 31, 2017. This amount represents earnings reinvested as part of the company's ongoing international business. It is not practicable to estimate the amount of state and foreign taxes that might be payable on the possible remittance of earnings that are intended to be reinvested indefinitely. 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, 2017, 2016 and 2015. 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.

	2017	2016	2015
Balance at January 1	**$ 3,031**	$ 3,042	$ 3,552
Foreign currency effects	**43**	1	(27)
Additions based on tax positions taken in current year	**1,853**	245	154
Additions for tax positions taken in prior years	**1,166**	181	218
Reductions for tax positions taken in prior years	**(90)**	(390)	(678)
Settlements with taxing authorities in current year	**(1,173)**	(36)	(5)
Reductions as a result of a lapse of the applicable statute of limitations	**(2)**	(12)	(172)
Balance at December 31	**$ 4,828**	$ 3,031	$ 3,042

The increase in unrecognized tax benefits between December 31, 2016 and December 31, 2017 was primarily due to foreign tax credits associated with the deemed repatriation. The increase in unrecognized tax benefits related to these foreign tax credits had no impact on the effective tax rate since the change to the deferred tax asset was fully offset with a change to the valuation allowance. The resolution of numerous issues with various tax jurisdictions during the year also impacted the movement from December 31, 2016 and December 31, 2017.

Approximately 81 percent of the $4,828 of unrecognized tax benefits at December 31, 2017, 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, 2017. For these jurisdictions, the latest years for which income tax examinations had been finalized were as follows: United States – 2011, Nigeria – 2000, Australia – 2006, Angola – 2016 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 April 21, 2017, an adverse decision was issued by the full Federal Court on Australia regarding the interest rate to be applied on certain Chevron intercompany loans. On August 14, 2017, an agreement was reached with the Australian Taxation Office to settle this dispute. Management believes the agreed terms to be a reasonable resolution of the dispute, which did not have a material impact on the 2017 results of the company.

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, 2017, accruals of $178 for anticipated interest and penalty obligations were included on the Consolidated Balance Sheet, compared with accruals of $424 as of year-end 2016. Income tax expense (benefit) associated with interest and penalties was $(161), $38 and $195 in 2017, 2016 and 2015, respectively.

Taxes Other Than on Income

	Year ended December 31		
	2017	2016	2015
United States			
Excise and similar taxes on products and merchandise	**$ 4,398**	$ 4,335	$ 4,426
Import duties and other levies	**11**	9	4
Property and other miscellaneous taxes	**1,824**	1,680	1,367
Payroll taxes	**241**	252	270
Taxes on production	**206**	159	157
Total United States	**6,680**	6,435	6,224
International			
Excise and similar taxes on products and merchandise	**2,791**	2,570	2,933
Import duties and other levies	**45**	33	40
Property and other miscellaneous taxes	**2,563**	2,379	2,548
Payroll taxes	**137**	145	161
Taxes on production	**115**	106	124
Total International	**5,651**	5,233	5,806
Total taxes other than on income	**$ 12,331**	$ 11,668	$ 12,030

Note 19
Short-Term Debt

	At December 31	
	2017	2016
Commercial paper[1]	**$ 5,379**	$ 10,410
Notes payable to banks and others with originating terms of one year or less	**—**	50
Current maturities of long-term debt[2]	**6,720**	6,253
Current maturities of long-term capital leases	**15**	14
Redeemable long-term obligations		
Long-term debt	**3,078**	3,113
Capital leases	**—**	—
Subtotal	**15,192**	19,840
Reclassified to long-term debt	**(10,000)**	(9,000)
Total short-term debt	**$ 5,192**	$ 10,840

1 Weighted-average interest rates at December 31, 2017 and 2016, were 1.30 percent and 0.74 percent, respectively.

2 Net of unamortized discounts and issuance costs.

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, 2017, the company had no interest rate swaps on short-term debt.

At December 31, 2017, the company had $10,000 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 $9,575 and allows the company to convert any amounts outstanding into a term loan for a period of up to one year, and a $425 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, 2017.

The company classified $10,000 and $9,000 of short-term debt as long-term at December 31, 2017 and 2016, 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 20

Long-Term Debt

Total long-term debt, excluding capital leases, at December 31, 2017, was $33,477. The company's long-term debt outstanding at year-end 2017 and 2016 was as follows:

	At December 31	
	2017	2016
	Principal	Principal
3.191% notes due 2023	**$ 2,250**	$ 2,250
2.954% notes due 2026	**2,250**	2,250
1.718% notes due 2018	**2,000**	2,000
2.355% notes due 2022	**2,000**	2,000
1.365% notes due 2018	**1,750**	1,750
1.961% notes due 2020	**1,750**	1,750
Floating rate notes due 2018 (1.833%)[1]	**1,650**	1,650
4.950% notes due 2019	**1,500**	1,500
1.561% notes due 2019	**1,350**	1,350
2.100% notes due 2021	**1,350**	1,350
1.790% notes due 2018	**1,250**	1,250
2.419% notes due 2020	**1,250**	1,250
2.427% notes due 2020	**1,000**	1,000
2.895% notes due 2024	**1,000**	—
Floating rate notes due 2019 (1.684%)[1]	**850**	400
2.193% notes due 2019	**750**	750
2.566% notes due 2023	**750**	750
3.326% notes due 2025	**750**	750
2.498% notes due 2022	**700**	—
2.411% notes due 2022	**700**	700
Floating rate notes due 2021 (2.109%)[1]	**650**	650
Floating rate notes due 2022 (1.994%)[1]	**650**	350
1.991% notes due 2020	**600**	—
1.686% notes due 2019	**550**	—
Floating rate notes due 2020 (1.697%)[2]	**400**	—
8.625% debentures due 2032	**147**	147
8.625% debentures due 2031	**108**	108
8.000% debentures due 2032	**75**	75
Amortizing bank loan due 2018 (2.179%)[2]	**72**	178
9.750% debentures due 2020	**54**	54
8.875% debentures due 2021	**40**	40
Medium-term notes, maturing from 2021 to 2038 (6.283%)[1]	**38**	38
Floating rate notes due 2017	**—**	2,050
1.104% notes due 2017	**—**	2,000
1.345% notes due 2017	**—**	1,100
1.344% notes due 2017	**—**	1,000
Total including debt due within one year	**30,234**	32,490
Debt due within one year	**(6,722)**	(6,256)
Reclassified from short-term debt	**10,000**	9,000
Unamortized discounts and debt issuance costs	**(35)**	(41)
Total long-term debt	**$ 33,477**	$ 35,193

1 Weighted-average interest rate at December 31, 2017.
2 Interest rate at December 31, 2017.

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 $30,234 matures as follows: 2018 – $6,722; 2019 – $5,000; 2020 – $5,054; 2021 – $2,054; 2022 – $4,050; and after 2022 – $7,354.

The company completed a bond issuance of $4,000 in first quarter 2017.

See Note 10, beginning on page 64, for information concerning the fair value of the company’s long-term debt.

Note 21

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, 2017:

		2017		2016		2015
Beginning balance at January 1	**$**	**3,540**	$	3,312	$	4,195
Additions to capitalized exploratory well costs pending the determination of proved reserves		**323**		465		869
Reclassifications to wells, facilities and equipment based on the determination of proved reserves		**(113)**		(119)		(164)
Capitalized exploratory well costs charged to expense		**(39)**		(118)		(1,397)
Other reductions*		**(9)**		—		(191)
Ending balance at December 31	**$**	**3,702**	$	3,540	$	3,312

* 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					
		2017		2016		2015
Exploratory well costs capitalized for a period of one year or less	**$**	**307**	$	445	$	489
Exploratory well costs capitalized for a period greater than one year		**3,395**		3,095		2,823
Balance at December 31	**$**	**3,702**	$	3,540	$	3,312
Number of projects with exploratory well costs that have been capitalized for a period greater than one year*		**32**		35		39

* Certain projects have multiple wells or fields or both.

Of the $3,395 of exploratory well costs capitalized for more than one year at December 31, 2017, $2,257 (17 projects) is related to projects that had drilling activities underway or firmly planned for the near future. The $1,138 balance is related to 15 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 $1,138 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) $99 (one project) – development concept under review by government; (c) $826 (seven projects) – development alternatives under review; (d) $23 (five projects) – miscellaneous activities for projects with smaller amounts suspended. While progress was being made on all 32 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 $3,395 of suspended well costs capitalized for a period greater than one year as of December 31, 2017, represents 158 exploratory wells in 32 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
1998-2006	$	318	29
2007-2011		879	50
2012-2016		2,198	79
Total	$	3,395	158

Aging based on drilling completion date of last suspended well in project:		Amount	Number of projects
2003-2009	$	344	5
2010-2013		367	6
2014-2017		2,684	21
Total	$	3,395	32

Note 22

Stock Options and Other Share-Based Compensation

Compensation expense for stock options for 2017, 2016 and 2015 was $137 ($89 after tax), $271 ($176 after tax) and $312 ($203 after tax), respectively. In addition, compensation expense for stock appreciation rights, restricted stock, performance shares and restricted stock units was $231 ($150 after tax), $371 ($241 after tax) and $32 ($21 after tax) for 2017, 2016 and 2015, respectively. No significant stock-based compensation cost was capitalized at December 31, 2017, or December 31, 2016.

Cash received in payment for option exercises under all share-based payment arrangements for 2017, 2016 and 2015 was $1,100, $647 and $195, respectively. Actual tax benefits realized for the tax deductions from option exercises were $48, $21 and $17 for 2017, 2016 and 2015, respectively.

Cash paid to settle performance shares and stock appreciation rights was $187, $82 and $104 for 2017, 2016 and 2015, 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 issued before January 1, 2017, 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 issued after January 1, 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 2017, 2016 and 2015 were measured on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	Year ended December 31		
	2017	2016	2015
Expected term in years[1]	**6.3**	6.3	6.1
Volatility[2]	**21.7 %**	21.7 %	21.9 %
Risk-free interest rate based on zero coupon U.S. treasury note	**2.2 %**	1.6 %	1.4 %
Dividend yield	**4.2 %**	4.5 %	3.6 %
Weighted-average fair value per option granted	**$ 15.31**	$ 9.53	$ 13.89

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 2017 is presented below:

	Shares (Thousands)	Weighted-Average Exercise Price	Averaged Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at January 1, 2017	112,275	$ 94.99		
Granted	5,877	$ 117.16		
Exercised	(13,110)	$ 84.86		
Forfeited	(1,277)	$ 105.02		
Outstanding at December 31, 2017	103,765	$ 97.40	5.63	$ 2,883
Exercisable at December 31, 2017	78,120	$ 98.54	4.82	$ 2,082

The total intrinsic value (i.e., the difference between the exercise price and the market price) of options exercised during 2017, 2016 and 2015 was $407, $240 and $120, respectively. During this period, the company continued its practice of issuing treasury shares upon exercise of these awards.

As of December 31, 2017, there was $88 of total unrecognized before-tax compensation cost related to nonvested share-based compensation arrangements granted under the plan. That cost is expected to be recognized over a weighted-average period of 1.4 years.

At January 1, 2017, the number of LTIP performance shares outstanding was equivalent to 2,393,428 shares. During 2017, 1,623,526 performance shares were granted, 708,192 shares vested with cash proceeds distributed to recipients and 217,969 shares were forfeited. At December 31, 2017, performance shares outstanding were 3,090,793. The fair value of the liability recorded for these instruments was $340, and was measured using the Monte Carlo simulation method.

At January 1, 2017, the number of restricted stock units outstanding was equivalent to 557,415 shares. During 2017, 892,991 restricted stock units were granted, 96,210 units vested with cash proceeds distributed to recipients and 117,696 units were forfeited. At December 31, 2017, restricted stock units outstanding were 1,236,500. The fair value of the liability recorded for the vested portion of these instruments was $98, valued at the stock price as of December 31, 2017. In addition, outstanding stock appreciation rights that were granted under LTIP totaled approximately 4.6 million equivalent shares as of December 31, 2017. The fair value of the liability recorded for the vested portion of these instruments was $115.

Note 23

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 2017 and 2016 follows:

	Pension Benefits				Other Benefits	
	2017		2016			
	U.S.	**Int’l.**	U.S.	Int’l.	**2017**	2016
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 13,271**	**$ 5,169**	$ 13,563	$ 5,336	**$ 2,549**	$ 3,324
Service cost	**489**	**151**	494	159	**32**	60
Interest cost	**366**	**219**	377	261	**95**	128
Plan participants' contributions	**—**	**4**	—	5	**78**	148
Plan amendments	**—**	**1**	—	—	**—**	(345)
Actuarial (gain) loss	**1,168**	**(37)**	903	426	**266**	(437)
Foreign currency exchange rate changes	**—**	**374**	—	(524)	**10**	8
Benefits paid	**(1,714)**	**(310)**	(2,066)	(494)	**(229)**	(337)
Divestitures	**—**	**(31)**	—	—	**(13)**	—
Benefit obligation at December 31	**13,580**	**5,540**	13,271	5,169	**2,788**	2,549
Change in Plan Assets						
Fair value of plan assets at January 1	**9,550**	**4,174**	10,274	4,109	**—**	—
Actual return on plan assets	**1,384**	**319**	936	642	**—**	—
Foreign currency exchange rate changes	**—**	**358**	—	(552)	**—**	—
Employer contributions	**728**	**252**	406	464	**151**	189
Plan participants' contributions	**—**	**4**	—	5	**78**	148
Benefits paid	**(1,714)**	**(310)**	(2,066)	(494)	**(229)**	(337)
Divestitures	**—**	**(31)**	—	—	**—**	—
Fair value of plan assets at December 31	**9,948**	**4,766**	9,550	4,174	**—**	—
Funded status at December 31	**$ (3,632)**	**$ (774)**	$ (3,721)	$ (995)	**$ (2,788)**	$ (2,549)

Amounts recognized on the Consolidated Balance Sheet for the company's pension and OPEB plans at December 31, 2017 and 2016, include:

	Pension Benefits								Other Benefits			
	2017				2016							
		U.S.		Int'l.		U.S.		Int'l.		2017		2016
Deferred charges and other assets	**$**	**21**	**$**	**448**	$	16	$	199	**$**	**—**	$	—
Accrued liabilities		**(188)**		**(100)**		(222)		(75)		**(174)**		(163)
Noncurrent employee benefit plans		**(3,465)**		**(1,122)**		(3,515)		(1,119)		**(2,614)**		(2,386)
Net amount recognized at December 31	**$**	**(3,632)**	**$**	**(774)**	$	(3,721)	$	(995)	**$**	**(2,788)**	$	(2,549)

Amounts recognized on a before-tax basis in "Accumulated other comprehensive loss" for the company's pension and OPEB plans were $5,286 and $5,511 at the end of 2017 and 2016, respectively. These amounts consisted of:

	Pension Benefits								Other Benefits			
	2017				2016							
		U.S.		Int'l.		U.S.		Int'l.		2017		2016
Net actuarial loss	**$**	**4,258**	**$**	**1,005**	$	4,653	$	1,145	**$**	**207**	$	(82)
Prior service (credit) costs		**9**		**94**		4		106		**(287)**		(315)
Total recognized at December 31	**$**	**4,267**	**$**	**1,099**	$	4,657	$	1,251	**$**	**(80)**	$	(397)

The accumulated benefit obligations for all U.S. and international pension plans were $12,194 and $5,009, respectively, at December 31, 2017, and $11,954 and $4,676, respectively, at December 31, 2016.

Information for U.S. and international pension plans with an accumulated benefit obligation in excess of plan assets at December 31, 2017 and 2016, was:

	Pension Benefits							
	2017				2016			
		U.S.		Int'l.		U.S.		Int'l.
Projected benefit obligations	**$**	**13,514**	**$**	**1,590**	$	13,208	$	1,449
Accumulated benefit obligations		**12,129**		**1,326**		11,891		1,258
Fair value of plan assets		**9,862**		**413**		9,471		287

The components of net periodic benefit cost and amounts recognized in the Consolidated Statement of Comprehensive Income for 2017, 2016 and 2015 are shown in the table below:

	Pension Benefits												Other Benefits					
	2017				2016				2015									
		U.S.		Int'l.		U.S.		Int'l.		U.S.		Int'l.		2017		2016		2015
Net Periodic Benefit Cost																		
Service cost	**$**	**489**	**$**	**151**	$	494	$	159	$	538	$	185	**$**	**32**	$	60	$	72
Interest cost		**366**		**219**		377		261		502		277		**95**		128		151
Expected return on plan assets		**(597)**		**(239)**		(723)		(243)		(783)		(262)		**—**		—		—
Amortization of prior service costs (credits)		**(5)**		**13**		(9)		14		(8)		22		**(28)**		14		14
Recognized actuarial losses		**340**		**44**		335		47		356		78		**(5)**		19		34
Settlement losses		**436**		**2**		511		6		320		6		**—**		—		—
Curtailment losses (gains)		**—**		**—**		—		—		—		(14)		**—**		—		—
Total net periodic benefit cost		**1,029**		**190**		985		244		925		292		**94**		221		271
Changes Recognized in Comprehensive Income																		
Net actuarial (gain) loss during period		**381**		**(94)**		690		55		513		(260)		**284**		(430)		(362)
Amortization of actuarial loss		**(776)**		**(46)**		(846)		(53)		(676)		(84)		**5**		(19)		(34)
Prior service (credits) costs during period		**—**		**1**		—		—		—		(6)		**—**		(345)		—
Amortization of prior service (costs) credits		**5**		**(13)**		9		(14)		8		(24)		**28**		(14)		(14)
Total changes recognized in other comprehensive income		**(390)**		**(152)**		(147)		(12)		(155)		(374)		**317**		(808)		(410)

Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 639**	**$ 38**	$ 838	$ 232	$ 770	$ (82)	**$ 411**	$ (587)	$ (139)

Net actuarial losses recorded in “Accumulated other comprehensive loss” at December 31, 2017, for the company’s U.S. pension, international pension and OPEB plans are being amortized on a straight-line basis over approximately 10, 12 and 15 years, respectively. These amortization periods represent the estimated average remaining service of employees expected to receive benefits under the plans. These losses are amortized to the extent they exceed 10 percent of the higher of the projected benefit obligation or market-related value of plan assets. The amount subject to amortization is determined on a plan-by-plan basis. During 2018, the company estimates actuarial losses of $303, $30 and $15 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 $334 will be recognized from “Accumulated other comprehensive loss” during 2018 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, 2017, was approximately 5 and 9 years for U.S. and international pension plans, respectively, and 9 years for OPEB plans. During 2018, the company estimates prior service (credits) costs of $2, $11 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		
	2017		2016		2015				
	U.S.	**Int’l.**	U.S.	Int’l.	U.S.	Int’l.	**2017**	2016	2015
Assumptions used to determine benefit obligations:									
Discount rate	**3.5%**	**3.9%**	3.9%	4.3%	4.0%	5.3%	**3.8%**	4.3%	4.6%
Rate of compensation increase	**4.5%**	**4.0%**	4.5%	4.5%	4.5%	4.8%	**N/A**	N/A	N/A
Assumptions used to determine net periodic benefit cost:									
Discount rate for service cost	**4.2%**	**4.3%**	4.4%	5.3%	3.7%	5.0%	**4.6%**	4.9%	4.3%
Discount rate for interest cost	**3.0%**	**4.3%**	3.0%	5.3%	3.7%	5.0%	**3.8%**	4.0%	4.3%
Expected return on plan assets	**6.8%**	**5.5%**	7.3%	6.3%	7.5%	6.3%	**N/A**	N/A	N/A
Rate of compensation increase	**4.5%**	**4.5%**	4.5%	4.8%	4.5%	5.1%	**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 2017, the company used an expected long-term rate of return of 6.75 percent for U.S. pension plan assets, which account for 68 percent of the company’s pension plan assets. In 2016, the company used a long-term rate of return of 7.25 percent for this plan, and in 2015, 7.50 percent.

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. 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 2017 were 3.5 percent for the main U.S. pension plan and 3.6 percent for the main U.S. OPEB plan. The discount rates for these plans at the end of 2016 were 3.9 and 4.1 percent, respectively, while in 2015 they were 4.0 and 4.5 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 Assumed health care cost-trend rates can have a significant effect on the amounts reported for retiree health care costs. For the measurement of accumulated postretirement benefit obligation at December 31, 2017, for the main U.S. OPEB plan, the assumed health care cost-trend rates start with 7.4 percent in 2018 and gradually decline to 4.5 percent for 2025 and beyond. For this measurement at December 31, 2016, the assumed health care cost-trend rates started with 6.9 percent in 2017 and gradually declined to 4.5 percent for 2025 and beyond. The annual increase to the company's pre-Medicare medical contributions for the main U.S. plan upon retirement is capped at 4 percent. 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	$ 12	$ (10)
Effect on postretirement benefit obligation	$ 188	$ (155)

Plan Assets and Investment Strategy

The fair value measurements of the company’s pension plans for 2017 and 2016 are below:

	U.S.					Int’l.				
	Total	Level 1	Level 2	Level 3	NAV[1]	Total	Level 1	Level 2	Level 3	NAV[1]
At December 31, 2016										
Equities										
U.S.[2]	$ 1,217	$ 1,217	$ —	$ —	—	$ 565	$ 564	$ 1	$ —	$ —
International	1,832	1,822	10	—	—	576	576	—	—	—
Collective Trusts/Mutual Funds[3]	1,132	24	—	—	1,108	196	8	2	—	186
Fixed Income										
Government[4]	222	—	222	—	—	286	51	235	—	—
Corporate[4]	1,356	—	1,356	—	—	509	22	468	19	—
Bank Loans	118	—	107	11	—	—	—	—	—	—
Mortgage/Asset Backed	1	—	1	—	—	10	—	10	—	—
Collective Trusts/Mutual Funds[3,4]	1,031	—	—	—	1,031	1,278	—	17	—	1,261
Mixed Funds[5]	—	—	—	—	—	72	2	70	—	—
Real Estate[6]	1,367	—	—	—	1,367	331	—	—	60	271
Alternative Investments[7]	955	—	—	—	955	—	—	—	—	—
Cash and Cash Equivalents	252	243	9	—	—	331	325	6	—	—
Other[8]	67	(9)	25	42	9	20	—	18	2	—
Total at December 31, 2016	$ 9,550	$ 3,297	$ 1,730	$ 53	4,470	$ 4,174	$ 1,548	$ 827	$ 81	$ 1,718
At December 31, 2017										
Equities										
U.S.[2]	**$ 1,331**	**$ 1,331**	**$ —**	**$ —**	**$ —**	**$ 652**	**$ 651**	**$ 1**	**$ —**	**$ —**
International	**2,060**	**2,057**	**3**	**—**	**—**	**691**	**691**	**—**	**—**	**—**
Collective Trusts/Mutual Funds[3]	**1,089**	**22**	**—**	**—**	**1,067**	**204**	**19**	**4**	**—**	**181**
Fixed Income										
Government	**274**	**—**	**274**	**—**	**—**	**296**	**77**	**219**	**—**	**—**
Corporate	**1,492**	**—**	**1,492**	**—**	**—**	**593**	**—**	**563**	**30**	**—**
Bank Loans	**117**	**—**	**106**	**11**	**—**	**—**	**—**	**—**	**—**	**—**
Mortgage/Asset Backed	**1**	**—**	**1**	**—**	**—**	**8**	**—**	**8**	**—**	**—**
Collective Trusts/Mutual Funds[3]	**1,130**	**—**	**—**	**—**	**1,130**	**1,481**	**—**	**16**	**—**	**1,465**
Mixed Funds[5]	**—**	**—**	**—**	**—**	**—**	**80**	**1**	**79**	**—**	**—**
Real Estate[6]	**1,096**	**—**	**—**	**—**	**1,096**	**376**	**—**	**—**	**56**	**320**
Alternative Investments[7]	**1,022**	**—**	**—**	**—**	**1,022**	**—**	**—**	**—**	**—**	**—**
Cash and Cash Equivalents	**260**	**255**	**5**	**—**	**—**	**366**	**362**	**4**	**—**	**—**
Other[8]	**76**	**(2)**	**28**	**43**	**7**	**19**	**(2)**	**18**	**3**	**—**
Total at December 31, 2017	**$ 9,948**	**$ 3,663**	**$ 1,909**	**$ 54**	**$ 4,322**	**$ 4,766**	**$ 1,799**	**$ 912**	**$ 89**	**$ 1,966**

1 2016 has been adjusted to conform to the 2017 presentation of investments measured at Net Asset Value (NAV).
2 U.S. equities include investments in the company’s common stock in the amount of $12 at December 31, 2017, and $12 at December 31, 2016.
3 Collective Trusts/Mutual Funds for U.S. plans are entirely index funds; for International plans, they are mostly unit trust and index funds.
4 Certain International Fixed Income investments previously disclosed as Government or Corporate have been reclassified to Collective Trusts/Mutual Funds to conform to the 2017 presentation.
5 Mixed funds are composed of funds that invest in both equity and fixed-income instruments in order to diversify and lower risk.

[6] The year-end valuations of the U.S. real estate assets are based on third-party appraisals that occur at least once a year for each property in the portfolio.
[7] Alternative investments focus on market-neutral strategies that have a low expected correlation to traditional asset classes.
[8] 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 (Level 3); and investments in private-equity limited partnerships (NAV).

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, 2015[1]	$ 25	$ —	$ 97	$ 43	$ 165
Actual Return on Plan Assets:					
Assets held at the reporting date	1	—	(33)	—	(32)
Assets sold during the period	—	—	1	—	1
Purchases, Sales and Settlements	(7)	11	(5)	1	—
Transfers in and/or out of Level 3	—	—	—	—	—
Total at December 31, 2016[1]	$ 19	$ 11	$ 60	$ 44	$ 134
Actual Return on Plan Assets:					
Assets held at the reporting date	**1**	**—**	**1**	**—**	**2**
Assets sold during the period	**—**	**—**	**—**	**—**	**—**
Purchases, Sales and Settlements	**10**	**3**	**(5)**	**2**	**10**
Transfers in and/or out of Level 3	**—**	**(3)**	**—**	**—**	**(3)**
Total at December 31, 2017	**$ 30**	**$ 11**	**$ 56**	**$ 46**	**$ 143**

[1] 2015 and 2016 have been adjusted to conform to the 2017 presentation.

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. 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 2017, the company contributed $728 and $252 to its U.S. and international pension plans, respectively. In 2018, the company expects contributions to be approximately $700 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 $174 in 2018; $151 was paid in 2017.

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
2018	$ 1,465	$ 387	$ 174
2019	$ 1,331	$ 279	$ 175
2020	$ 1,296	$ 289	$ 175
2021	$ 1,261	$ 277	$ 175
2022	$ 1,234	$ 290	$ 174
2023-2027	$ 5,487	$ 1,609	$ 850

Employee Savings Investment Plan Eligible employees of Chevron and certain of its subsidiaries participate in the Chevron Employee Savings Investment Plan (ESIP). Compensation expense for the ESIP totaled $316, $281 and $316 in 2017, 2016 and 2015, 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 2017, 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, 2017 and 2016, trust assets of $35 and $35, 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 $936, $662 and $690 in 2017, 2016 and 2015, 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 22, beginning on page 81.

Note 24

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]		
	2017	2016	2015	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Upstream												
United States	**$ 84,602**	$ 83,929	$ 93,848	**$ 38,722**	$ 39,710	$ 43,125	**$ 4,995**	$ 4,432	$ 6,586	**$ 5,527**	$ 6,576	$ 8,545
International	**224,211**	214,557	208,395	**123,191**	125,502	127,459	**7,934**	12,084	19,993	**12,096**	11,247	10,803
Total Upstream	**308,813**	298,486	302,243	**161,913**	165,212	170,584	**12,929**	16,516	26,579	**17,623**	17,823	19,348
Downstream												
United States	**23,598**	22,795	23,202	**10,346**	10,196	10,807	**907**	528	696	**753**	956	878
International	**7,094**	9,350	9,177	**3,074**	4,094	4,090	**306**	375	365	**282**	332	355
Total Downstream	**30,692**	32,145	32,379	**13,420**	14,290	14,897	**1,213**	903	1,061	**1,035**	1,288	1,233
All Other												
United States	**4,798**	5,263	5,500	**2,341**	2,635	2,859	**218**	198	357	**677**	328	439
International	**182**	183	155	**38**	49	56	**4**	6	5	**14**	18	17
Total All Other	**4,980**	5,446	5,655	**2,379**	2,684	2,915	**222**	204	362	**691**	346	456
Total United States	**112,998**	111,987	122,550	**51,409**	52,541	56,791	**6,120**	5,158	7,639	**6,957**	7,860	9,862
Total International	**231,487**	224,090	217,727	**126,303**	129,645	131,605	**8,244**	12,465	20,363	**12,392**	11,597	11,175
Total	**$344,485**	$336,077	$340,277	**$177,712**	$182,186	$188,396	**$ 14,364**	$ 17,623	$ 28,002	**$ 19,349**	$ 19,457	$ 21,037

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 2017. Australia had PP&E of $55,514, $53,962 and $49,205 in 2017, 2016, and 2015, respectively. Nigeria had PP&E of $17,076, $17,922 and $18,773 for 2017, 2016 and 2015, respectively.
2 Net of dry hole expense related to prior years' expenditures of $42, $175 and $1,573 in 2017, 2016 and 2015, respectively.
3 Depreciation expense includes accretion expense of $668, $749 and $715 in 2017, 2016 and 2015, respectively, and impairments of $1,021, $3,186 and $4,066 in 2017, 2016 and 2015, respectively.

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 18, beginning on page 75, for a discussion of the periods for which tax returns have been audited for the company's major tax jurisdictions and a discussion for all tax jurisdictions of the differences between the amount of tax benefits recognized in the financial statements and the amount taken or expected to be taken in a tax return.

As discussed in Note 18, beginning on page 75, the company received an adverse decision on April 21, 2017, regarding the interest rate to be applied on certain Chevron intercompany loans. On August 14, 2017, an agreement was reached with the Australian Taxation Office to settle this dispute. Management believes the agreed terms to be a reasonable resolution of the dispute, which did not have a material impact on the 2017 results of the company.

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 $1,082. Of this amount, $712 is associated with a financing arrangement with an equity affiliate. Over the approximate 4-year remaining term of this guarantee, the maximum amount will be reduced as payments are made by the affiliate. The remaining amount of $370 is associated with certain payments under a terminal use agreement entered into by an equity affiliate. Over the approximate 10-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: 2018 – $1,402; 2019 – $1,367; 2020 – $1,027; 2021 – $920; 2022 – $555; 2023 and after – $2,566. A portion of these commitments may ultimately be shared with project partners. Total payments under the agreements were approximately $1,300 in 2017, $1,300 in 2016 and $1,900 in 2015.

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, 2017, was $1,429. Included in this balance was $269 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 2017 environmental reserves balance of $1,160, $781 is related to the company's U.S. downstream operations, $38 to its international downstream operations, $340 to upstream operations and $1 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 2017 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 89 for a discussion of the company's asset retirement obligations.

Other Contingencies 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 2017, 2016 and 2015:

		2017		2016		2015
Balance at January 1	**$**	**14,243**	$	15,642	$	15,053
Liabilities incurred		**684**		204		51
Liabilities settled		**(1,721)**		(1,658)		(981)
Accretion expense		**668**		749		715
Revisions in estimated cash flows		**340**		(694)		804
Balance at December 31	**$**	**14,214**	$	14,243	$	15,642

In the table above, the amount associated with "Revisions in estimated cash flows" in 2017 reflects increased cost estimates to abandon wells, equipment and facilities. The long-term portion of the $14,214 balance at the end of 2017 was $13,228.

Note 27

Other Financial Information

Earnings in 2017 included after-tax gains of approximately $1,800 relating to the sale of certain properties. Of this amount, approximately $850 and $950 related to downstream and upstream, respectively. Earnings in 2016 included after-tax gains of approximately $800 relating to the sale of certain properties, of which approximately $600 and $200 related to downstream and upstream assets, respectively. Earnings in 2017 included after-tax charges of approximately $900 for impairments and other asset write-offs related to upstream. 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.

Other financial information is as follows:

	Year ended December 31					
		2017		2016		2015
Total financing interest and debt costs	**$**	**902**	$	753	$	495
Less: Capitalized interest		**595**		552		495
Interest and debt expense	**$**	**307**	$	201	$	—
Research and development expenses	**$**	**433**	$	476	$	601
Excess of replacement cost over the carrying value of inventories (LIFO method)	**$**	**3,937**	$	2,942	$	3,745
LIFO losses on inventory drawdowns included in earnings	**$**	**(5)**	$	(88)	$	(65)
Foreign currency effects*	**$**	**(446)**	$	58	$	769

* Includes $(45), $1 and $344 in 2017, 2016 and 2015, respectively, for the company's share of equity affiliates' foreign currency effects.

The company has $4,531 in goodwill on the Consolidated Balance Sheet, all of which is in the upstream segment and related primarily to the 2005 acquisition of Unocal. The company tested this goodwill for impairment during 2017, and no impairment was required.

Millions of dollars, except per-share amounts	**2017**	2016	2015	2014	2013
Statement of Income Data					
Revenues and Other Income					
Total sales and other operating revenues*	**$ 134,674**	$ 110,215	$ 129,925	$ 200,494	$ 220,156
Income from equity affiliates and other income	**7,048**	4,257	8,552	11,476	8,692
Total Revenues and Other Income	**141,722**	114,472	138,477	211,970	228,848
Total Costs and Other Deductions	**132,501**	116,632	133,635	180,768	192,943
Income Before Income Tax Expense (Benefit)	**9,221**	(2,160)	4,842	31,202	35,905
Income Tax Expense (Benefit)	**(48)**	(1,729)	132	11,892	14,308
Net Income	**9,269**	(431)	4,710	19,310	21,597
Less: Net income attributable to noncontrolling interests	**74**	66	123	69	174
Net Income (Loss) Attributable to Chevron Corporation	**$ 9,195**	$ (497)	$ 4,587	$ 19,241	$ 21,423
Per Share of Common Stock					
Net Income (Loss) Attributable to Chevron					
– Basic	**$ 4.88**	$ (0.27)	$ 2.46	$ 10.21	$ 11.18
– Diluted	**$ 4.85**	$ (0.27)	$ 2.45	$ 10.14	$ 11.09
Cash Dividends Per Share	**$ 4.32**	$ 4.29	$ 4.28	$ 4.21	$ 3.90
Balance Sheet Data (at December 31)					
Current assets	**$ 28,560**	$ 29,619	$ 34,430	$ 41,161	$ 48,909
Noncurrent assets	**225,246**	230,459	230,110	223,723	203,884
Total Assets	**253,806**	260,078	264,540	264,884	252,793
Short-term debt	**5,192**	10,840	4,927	3,790	374
Other current liabilities	**22,545**	20,945	20,540	27,322	32,061
Long-term debt and capital lease obligations	**33,571**	35,286	33,622	23,994	20,027
Other noncurrent liabilities	**43,179**	46,285	51,565	53,587	49,904
Total Liabilities	**104,487**	113,356	110,654	108,693	102,366
Total Chevron Corporation Stockholders' Equity	**$ 148,124**	$ 145,556	$ 152,716	$ 155,028	$ 149,113
Noncontrolling interests	**1,195**	1,166	1,170	1,163	1,314
Total Equity	**$ 149,319**	$ 146,722	$ 153,886	$ 156,191	$ 150,427
* Includes excise, value-added and similar taxes:	**$ 7,189**	$ 6,905	$ 7,359	$ 8,186	$ 8,492

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

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, 2017									
Exploration									
Wells	**$ 479**	**$ 3**	**$ 1**	**$ 36**	**$ —**	**$ 15**	**$ 534**	**$ —**	**$ —**
Geological and geophysical	**93**	**46**	**4**	**3**	**33**	**5**	**184**	**—**	**—**
Rentals and other	**157**	**32**	**52**	**60**	**46**	**128**	**475**	**—**	**—**
Total exploration	**729**	**81**	**57**	**99**	**79**	**148**	**1,193**	**—**	**—**
Property acquisitions[2]									
Proved	**64**	**—**	**—**	**93**	**—**	**—**	**157**	**—**	**—**
Unproved	**77**	**—**	**40**	**18**	**1**	**—**	**136**	**—**	**—**
Total property acquisitions	**141**	**—**	**40**	**111**	**1**	**—**	**293**	**—**	**—**
Development[3]	**4,346**	**944**	**1,136**	**1,324**	**2,580**	**121**	**10,451**	**3,596**	**147**
Total Costs Incurred[4]	**$ 5,216**	**$ 1,025**	**$ 1,233**	**$ 1,534**	**$ 2,660**	**$ 269**	**$ 11,937**	**$ 3,596**	**$ 147**
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

[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 89.

[2] Does not include properties acquired in nonmonetary transactions.

[3] Includes $84, $481 and $325 costs incurred on major capital projects prior to assignment of proved reserves for consolidated companies in 2017, 2016, and 2015, respectively.

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

	2017	2016	2015
Total cost incurred	$ 15.7	$ 17.6	$ 28.6

Non-oil and gas activities	1.4	2.5	3.5	(Primarily includes LNG, gas-to-liquids and transportation activities.)
ARO	(0.6)	—	(1.0)	
Upstream C&E	$ 16.4	$ 20.1	$ 31.1	Reference page 41 Upstream total

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 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 70, 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, 2017									
Unproved properties	**$ 6,466**	**$ 2,314**	**$ 240**	**$ 1,420**	**$ 1,986**	**$ 23**	**$ 12,449**	**$ 108**	**$ —**
Proved properties and related producing assets	**66,390**	**20,696**	**43,656**	**55,616**	**21,544**	**10,697**	**218,599**	**8,956**	**4,346**
Support equipment	**2,248**	**337**	**1,104**	**2,050**	**15,599**	**132**	**21,470**	**1,731**	**—**
Deferred exploratory wells	**969**	**181**	**406**	**562**	**1,323**	**261**	**3,702**	**—**	**—**
Other uncompleted projects	**8,333**	**3,624**	**2,528**	**1,889**	**3,238**	**1,966**	**21,578**	**8,098**	**457**
Gross Capitalized Costs	**84,406**	**27,152**	**47,934**	**61,537**	**43,690**	**13,079**	**277,798**	**18,893**	**4,803**
Unproved properties valuation	**977**	**855**	**162**	**535**	**107**	**23**	**2,659**	**58**	**—**
Proved producing properties – Depreciation and depletion	**43,286**	**11,795**	**27,916**	**40,234**	**3,193**	**9,306**	**135,730**	**4,690**	**1,468**
Support equipment depreciation	**1,359**	**227**	**712**	**1,584**	**870**	**123**	**4,875**	**846**	**—**
Accumulated provisions	**45,622**	**12,877**	**28,790**	**42,353**	**4,170**	**9,452**	**143,264**	**5,594**	**1,468**
Net Capitalized Costs	**$ 38,784**	**$ 14,275**	**$ 19,144**	**$ 19,184**	**$ 39,520**	**$ 3,627**	**$ 134,534**	**$ 13,299**	**$ 3,335**
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

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 2017, 2016 and 2015 are shown in the following table. Net income (loss) from exploration and production activities as reported on page 68 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 68.

	Consolidated Companies							Affiliated Companies	
Millions of dollars	U.S.	Other Americas	Africa	Asia	Australia/ Oceania	Europe	Total	TCO	Other
Year Ended December 31, 2017									
Revenues from net production									
Sales	**$ 1,548**	**$ 999**	**$ 487**	**$ 5,381**	**$ 2,061**	**$ 372**	**$ 10,848**	**$ 4,509**	**$ 1,218**
Transfers	**7,610**	**1,371**	**6,533**	**2,966**	**937**	**1,246**	**20,663**	**—**	**—**
Total	**9,158**	**2,370**	**7,020**	**8,347**	**2,998**	**1,618**	**31,511**	**4,509**	**1,218**
Production expenses excluding taxes	**(3,160)**	**(1,021)**	**(1,521)**	**(2,670)**	**(304)**	**(415)**	**(9,091)**	**(425)**	**(306)**
Taxes other than on income	**(403)**	**(85)**	**(115)**	**(11)**	**(183)**	**(3)**	**(800)**	**118**	**(121)**
Proved producing properties:									
Depreciation and depletion	**(5,092)**	**(1,046)**	**(3,531)**	**(4,134)**	**(1,176)**	**(668)**	**(15,647)**	**(638)**	**(365)**
Accretion expense[2]	**(212)**	**(23)**	**(144)**	**(155)**	**(40)**	**(60)**	**(634)**	**(3)**	**(16)**
Exploration expenses	**(299)**	**(126)**	**(65)**	**(108)**	**(85)**	**(149)**	**(832)**	**—**	**—**
Unproved properties valuation	**(204)**	**(259)**	**(3)**	**(52)**	**—**	**—**	**(518)**	**—**	**—**
Other income (expense)[3]	**580**	**(87)**	**259**	**273**	**170**	**(170)**	**1,025**	**(104)**	**(14)**
Results before income taxes	**368**	**(277)**	**1,900**	**1,490**	**1,380**	**153**	**5,014**	**3,457**	**396**
Income tax (expense) benefit	**(88)**	**(64)**	**(1,199)**	**(616)**	**(413)**	**(174)**	**(2,554)**	**(1,037)**	**20**
Results of Producing Operations	**$ 280**	**$ (341)**	**$ 701**	**$ 874**	**$ 967**	**$ (21)**	**$ 2,460**	**$ 2,420**	**$ 416**
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)

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 89.
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, 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	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 89.
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, 2017									
Average sales prices									
Liquids, per barrel	**$ 44.53**	**$ 51.26**	**$ 52.12**	**$ 48.45**	**$ 52.32**	**$ 51.15**	**$ 48.61**	**$ 41.47**	**$ 48.68**
Natural gas, per thousand cubic feet	**2.11**	**3.15**	**1.77**	**4.12**	**5.75**	**5.55**	**4.07**	**0.88**	**2.38**
Average production costs, per barrel[2]	**12.83**	**18.64**	**10.88**	**11.30**	**3.60**	**11.95**	**11.41**	**3.34**	**8.51**
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

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

	2017			2016			2015		
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.	**1,031**	**—**	**2,096**	992	—	2,102	933	—	2,683
Other Americas	**101**	**543**	**398**	92	601	533	109	594	597
Africa	**664**	**—**	**1,276**	640	—	1,039	702	—	1,100
Asia	**529**	**—**	**4,463**	621	—	4,962	660	—	4,933
Australia/Oceania	**126**	**—**	**9,907**	124	—	9,176	60	—	4,330
Europe	**83**	**—**	**215**	77	—	213	76	—	166
Total Consolidated	**2,534**	**543**	**18,355**	2,546	601	18,025	2,540	594	13,809
Affiliated Companies									
TCO	**787**	**—**	**1,300**	920	—	1,402	1,020	—	1,504
Other	**84**	**66**	**270**	92	62	319	91	58	288
Total Consolidated and Affiliated Companies	**3,405**	**609**	**19,925**	3,558	663	19,746	3,651	652	15,601
Proved Undeveloped									
Consolidated Companies									
U.S.	**885**	**—**	**3,084**	420	—	1,574	453	—	1,559
Other Americas	**196**	**—**	**397**	131	3	114	127	3	117
Africa	**175**	**—**	**1,630**	236	—	1,788	255	—	1,837
Asia	**102**	**—**	**310**	99	—	571	130	—	1,023
Australia/Oceania	**33**	**—**	**3,652**	34	—	3,339	93	—	7,543
Europe	**62**	**—**	**86**	61	—	21	67	—	58
Total Consolidated	**1,453**	**—**	**9,159**	981	3	7,407	1,125	3	12,137
Affiliated Companies									
TCO	**962**	**—**	**883**	989	—	840	656	—	764
Other	**20**	**93**	**769**	26	108	767	40	135	935
Total Consolidated and Affiliated Companies	**2,435**	**93**	**10,811**	1,996	111	9,014	1,821	138	13,836
Total Proved Reserves	**5,840**	**702**	**30,736**	5,554	774	28,760	5,472	790	29,437

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 reserves: 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 2017, 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 2017, proved undeveloped reserves totaled 4.3 billion barrels of oil-equivalent (BOE), an increase of 721 million BOE from year-end 2016. The increase was due to 736 million BOE in extensions and discoveries, 366 million BOE in revisions, 39 million BOE in acquisitions and 5 million BOE in improved recovery, partially offset by the transfer of 419 million BOE to proved developed and 6 million BOE in sales. A major portion of this reserve increase is attributed to the company's activities in the Midland and Delaware basins.

During 2017, investments totaling approximately $9.1 billion in oil and gas producing activities and about $0.1 billion in non-oil and gas producing activities were expended to advance the development of proved undeveloped reserves. In Asia, expenditures during the year totaled approximately $4.0 billion, primarily related to development projects of the TCO affiliate in Kazakhstan. The United States accounted for about $3.3 billion related primarily to various development activities in the Gulf of Mexico and the Midland and Delaware basins. In Africa, about $0.7 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 $0.8 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 2017, the company held approximately 2.3 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 completed construction of liquefaction and other facilities to develop this natural gas. Further field development to convert the remaining proved undeveloped reserves is scheduled to occur in line with reservoir depletion. 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 2017, increases in commodity prices positively impacted the economic limits of oil and gas properties, resulting in proved reserve increases, and negatively 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 2017, 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 38 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, 2017, 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, 2017, proved reserves for the company were 11.7 billion BOE. The company's estimated net proved reserves of liquids including crude oil, condensate, natural gas liquids and synthetic oil for the years 2015, 2016 and 2017 are shown in the table on page 98. The company's estimated net proved reserves of natural gas are shown on page 99.

Noteworthy changes in liquids proved reserves for 2015 through 2017 are discussed below and shown in the table on the following page:

Revisions 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.

In 2017, improved field performance at various Gulf of Mexico fields, including Jack/St Malo and Tahiti, and in the Midland and Delaware basins were primarily responsible for the 280 million barrel increase in the United States. Improved field performance at various fields, including Agbami and Sonam in Nigeria, were responsible for the 79 million barrel increase in Africa. Synthetic oil reserves in Canada decreased by 42 million barrels, primarily due to entitlement effects. In the TCO affiliate in Kazakhstan, entitlement effects were mainly responsible for the 53 million barrel decrease.

Improved Recovery 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 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.

In 2017, extensions and discoveries in the Midland and Delaware basins and the Gulf of Mexico were primarily responsible for the 458 million barrel increase in the United States. Extensions and discoveries in the Duvernay Shale in Canada were primarily responsible for the 74 million barrel increase in Other Americas.

Purchases In 2017, purchases of 33 million barrels in Asia were due to contract extension in the Azeri-Chirag-Gunashli fields in Azerbaijan.

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

In 2017, sales of 57 million barrels in the United States were primarily in the Gulf of Mexico shelf and in the Midland and Delaware basins.

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

	Consolidated Companies								Affiliated Companies			Total Consolidated and Affiliated
Millions of barrels	U.S.	Other Americas[1]	Africa	Asia	Australia/ Oceania	Europe	Synthetic Oil[2]	Total	TCO	Synthetic Oil	Other[3]	Companies
Reserves at January 1, 2015	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
Changes attributable to:												
Revisions	**280**	**25**	**79**	**(17)**	**11**	**30**	**(42)**	**366**	**(53)**	**—**	**(5)**	**308**
Improved recovery	**9**	**—**	**7**	**1**	**—**	**—**	**—**	**17**	**—**	**—**	**3**	**20**
Extensions and discoveries	**458**	**74**	**4**	**—**	**—**	**—**	**—**	**536**	**—**	**—**	**—**	**536**
Purchases	**4**	**—**	**2**	**33**	**—**	**—**	**—**	**39**	**—**	**—**	**—**	**39**
Sales	**(57)**	**(1)**	**—**	**(2)**	**—**	**—**	**—**	**(60)**	**—**	**—**	**—**	**(60)**
Production	**(190)**	**(24)**	**(129)**	**(104)**	**(10)**	**(23)**	**(19)**	**(499)**	**(107)**	**(11)**	**(12)**	**(629)**
Reserves at December 31, 2017[4]	**1,916**	**297**	**839**	**631**	**159**	**145**	**543**	**4,530**	**1,749**	**159**	**104**	**6,542**

1 Ending reserve balances in North America were 234, 169 and 155 and in South America were 63, 54 and 81 in 2017, 2016 and 2015, respectively.
2 Reserves associated with Canada.
3 Ending reserve balances in Africa were 26, 31 and 34 and in South America were 78, 87 and 97 in 2017, 2016 and 2015, respectively.
4 Included are year-end reserve quantities related to production-sharing contracts (PSC) (refer to page E-8 for the definition of a PSC). PSC-related reserve quantities are 15 percent, 19 percent and 20 percent for consolidated companies for 2017, 2016 and 2015, 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, 2015	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]	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[4]	3,676	647	2,827	5,533	12,515	234	25,432	2,242	1,086	28,760
Changes attributable to:										
Revisions	**670**	**39**	**184**	**65**	**1,545**	**143**	**2,646**	**87**	**48**	**2,781**
Improved recovery	**3**	**—**	**—**	**—**	**—**	**—**	**3**	**—**	**—**	**3**
Extensions and discoveries	**1,361**	**319**	**—**	**2**	**—**	**—**	**1,682**	**—**	**—**	**1,682**
Purchases	**1**	**—**	**2**	**46**	**—**	**—**	**49**	**—**	**—**	**49**
Sales	**(177)**	**(129)**	**—**	**(31)**	**—**	**—**	**(337)**	**—**	**—**	**(337)**
Production[3]	**(354)**	**(81)**	**(107)**	**(842)**	**(501)**	**(76)**	**(1,961)**	**(146)**	**(95)**	**(2,202)**
Reserves at December 31, 2017[4]	**5,180**	**795**	**2,906**	**4,773**	**13,559**	**301**	**27,514**	**2,183**	**1,039**	**30,736**

1 Ending reserve balances in North America and South America were 478, 172, 174 and 317, 475, 540 in 2017, 2016 and 2015, respectively.
2 Ending reserve balances in Africa and South America were 899, 939, 1,044 and 140, 147, 179 in 2017, 2016 and 2015, respectively.
3 Total "as sold" volumes are 1,995, 1,744 and 1,742 for 2017, 2016 and 2015, respectively.
4 Includes reserve quantities related to production-sharing contracts (PSC) (refer to page E-8 for the definition of a PSC). PSC-related reserve quantities are 12 percent, 15 percent and 16 percent for consolidated companies for 2017, 2016 and 2015, respectively.

Noteworthy changes in natural gas proved reserves for 2015 through 2017 are discussed below and shown in the table above:

Revisions 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.

In 2017, reservoir performance and new seismic data in the greater Gorgon area were primarily responsible for the 1.5 TCF increase in Australia. Improved performance in the Midland and Delaware basins were primarily responsible for the 670 BCF increase in the United States. The Sonam Field in Nigeria was primarily responsible for the 184 BCF increase in Africa.

Extensions and Discoveries 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.

In 2017, extensions and discoveries of 1.4 TCF in the United States were primarily in the Appalachian region and the Midland and Delaware basins. Extensions and discoveries in the Duvernay Shale in Canada were primarily responsible for the 319 BCF increase in Other Americas.

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

In 2017, sales of 177 BCF in the United States were primarily from the Midland and Delaware basins. Sale of the company's interests in Trinidad and Tobago was primarily responsible for the 129 BCF decrease in Other Americas.

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
		Other			Australia/					and Affiliated
Millions of dollars	U.S.	Americas	Africa	Asia	Oceania	Europe	Total	TCO	Other	Companies
At December 31, 2017										
Future cash inflows from production	**$ 94,086**	**$ 43,175**	**$ 47,828**	**$ 47,809**	**$ 77,557**	**$ 8,800**	**$319,255**	**$ 80,090**	**$ 13,632**	**$ 412,977**
Future production costs	**(29,049)**	**(20,044)**	**(18,124)**	**(18,640)**	**(12,315)**	**(6,345)**	**(104,517)**	**(22,050)**	**(4,635)**	**(131,202)**
Future development costs	**(10,849)**	**(5,102)**	**(3,808)**	**(4,755)**	**(6,682)**	**(1,114)**	**(32,310)**	**(17,564)**	**(1,760)**	**(51,634)**
Future income taxes	**(10,803)**	**(5,158)**	**(17,845)**	**(10,901)**	**(17,568)**	**(615)**	**(62,890)**	**(12,143)**	**(3,250)**	**(78,283)**
Undiscounted future net cash flows	**43,385**	**12,871**	**8,051**	**13,513**	**40,992**	**726**	**119,538**	**28,333**	**3,987**	**151,858**
10 percent midyear annual discount for timing of estimated cash flows	**(19,781)**	**(8,483)**	**(2,058)**	**(3,846)**	**(19,730)**	**207**	**(53,691)**	**(16,310)**	**(1,844)**	**(71,845)**
Standardized Measure Net Cash Flows	**$ 23,604**	**$ 4,388**	**$ 5,993**	**$ 9,667**	**$ 21,262**	**$ 933**	**$ 65,847**	**$ 12,023**	**$ 2,143**	**$ 80,013**
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 *	(5,123)	(3,646)	(1,336)	(3,137)	(15,284)	322	(28,204)	(13,902)	(972)	(43,078)
Standardized Measure Net Cash Flows	$ 10,840	$ 2,520	$ 4,117	$ 8,468	$ 16,159	$ 252	$ 42,356	$ 8,526	$ 1,187	$ 52,069
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 *	(5,921)	(2,833)	(2,207)	(3,673)	(26,121)	282	(40,473)	(15,249)	(2,242)	(57,964)
Standardized Measure Net Cash Flows	$ 10,934	$ 2,252	$ 5,715	$ 9,320	$ 23,666	$ 168	$ 52,055	$ 12,882	$ 2,045	$ 66,982

* Conforms to 2017 presentation.

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

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

Millions of dollars	Consolidated Companies	Affiliated Companies	Total Consolidated and Affiliated Companies
Present Value at January 1, 2015	$ 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 *	52,373	9,354	61,727
Net change for 2015	(57,466)	(20,904)	(78,370)
Present Value at December 31, 2015	$ 52,055	$ 14,927	$ 66,982
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 *	6,724	2,758	9,482
Net change for 2016	(9,700)	(5,213)	(14,913)
Present Value at December 31, 2016	$ 42,355	$ 9,714	$ 52,069
Sales and transfers of oil and gas produced net of production costs	**(21,505)**	**(5,234)**	**(26,739)**
Development costs incurred	**9,417**	**3,721**	**13,138**
Purchases of reserves	**105**	**—**	**105**
Sales of reserves	**(1,148)**	**—**	**(1,148)**
Extensions, discoveries and improved recovery less related costs	**3,716**	**—**	**3,716**
Revisions of previous quantity estimates	**11,132**	**(1,085)**	**10,047**
Net changes in prices, development and production costs	**28,754**	**8,013**	**36,767**
Accretion of discount	**6,116**	**1,398**	**7,514**
Net change in income tax	**(13,095)**	**(2,361)**	**(15,456)**
Net change for 2017	**23,492**	**4,452**	**27,944**
Present Value at December 31, 2017	**$ 65,847**	**$ 14,166**	**$ 80,013**

* Conforms to 2017 presentation.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

(1) Financial Statements:

	Page(s)
Report of Independent Registered Public Accounting Firm — PricewaterhouseCoopers LLP	51
Consolidated Statement of Income for the three years ended December 31, 2017	52
Consolidated Statement of Comprehensive Income for the three years ended December 31, 2017	53
Consolidated Balance Sheet at December 31, 2017 and 2016	54
Consolidated Statement of Cash Flows for the three years ended December 31, 2017	55
Consolidated Statement of Equity for the three years ended December 31, 2017	56
Notes to the Consolidated Financial Statements	57 to 89

(2) Financial Statement Schedules:

Included below is Schedule II - Valuation and Qualifying Accounts.

(3) Exhibits:

The Exhibit Index on the following pages lists the exhibits that are filed as part of this report.

Schedule II — Valuation and Qualifying Accounts

	Year ended December 31		
Millions of Dollars	**2017**	2016	2015
Employee Termination Benefits			
Balance at January 1	**$ 111**	$ 308	$ 49
Additions (reductions) charged to expense	**20**	160	342
Payments	**(69)**	(357)	(83)
Balance at December 31	**$ 62**	$ 111	$ 308
Allowance for Doubtful Accounts			
Balance at January 1	**$ 487**	$ 429	$ 194
Additions to expense	**128**	76	251
Bad debt write-offs	**(9)**	(18)	(16)
Balance at December 31	**$ 606**	$ 487	$ 429
Deferred Income Tax Valuation Allowance*			
Balance at January 1	**$ 16,069**	$ 15,412	$ 16,292
Additions to deferred income tax expense	**2,681**	1,810	1,440
Reduction of deferred income tax expense	**(2,176)**	(1,153)	(2,320)
Balance at December 31	**$ 16,574**	$ 16,069	$ 15,412

* See also Note 18 to the Consolidated Financial Statements, beginning on page 75.

Item 16. Form 10-K Summary

Not applicable.

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	Indenture, dated as of June 15, 1995, filed as Exhibit 4.1 to Chevron Corporation's Amendment Number 1 to Registration Statement on Form S-3 filed June 14, 1995, and incorporated herein by reference.
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 quarter 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+*	Amendment to the Chevron Incentive Plan, Effective January 31, 2018.
10.7+*	Summary of Chevron Incentive Plan Award Criteria.
10.8+	Long-Term Incentive Plan of Chevron Corporation, filed as Appendix B to Chevron Corporation's Notice of the 2013 Annual Meeting and 2013 Proxy Statement filed April 11, 2013, and incorporated herein by reference.
10.9+	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 February 2, 2018, and incorporated herein by reference.
10.10+	Form of Performance Share 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 February 2, 2018, and incorporated herein by reference.
10.11+	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 February 2, 2018, and incorporated herein by reference.
10.12+	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.
10.13+	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.
10.14+	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.
10.15+	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.

Exhibit No.	Description
10.16+	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.
10.17+	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.
10.18+	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.
10.19+	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.
10.20+	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.
10.21+	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.
10.22+	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.
10.23+*	Amendment Number One to the Chevron Corporation Retirement Restoration Plan.
10.24+	Chevron Corporation ESIP Restoration Plan, Amended and Restated as of January 1, 2018, filed as Exhibit 10.1 to Chevron Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017, and incorporated herein by reference.
10.25+	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-1).
21.1*	Subsidiaries of Chevron Corporation (page E-2).
23.1*	Consent of PricewaterhouseCoopers LLP (page E-3).
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-4).
31.2*	Rule 13a-14(a)/15d-14(a) Certification by the company's Chief Financial Officer (page E-5).
32.1*	Rule 13a-14(b)/15d-14(b) Certification by the company's Chief Executive Officer (page E-6).
32.2*	Rule 13a-14(b)/15d-14(b) Certification by the company's Chief Financial Officer (page E-7).
99.1*	Definitions of Selected Energy and Financial Terms (pages E-8 through E-9).
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."

+ Indicates a management contract or compensatory plan or arrangement.
*   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.

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 22nd day of February, 2018.

Chevron Corporation

By /s/ MICHAEL K. WIRTH

Michael K. Wirth, 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 22nd day of February, 2018.

Principal Executive Officer
(and Director)

/s/ MICHAEL K. WIRTH
Michael K. Wirth, 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

JOHN B. FRANK*
John B. Frank

ALICE P. GAST*
Alice P. Gast

ENRIQUE HERNANDEZ, JR.*
Enrique Hernandez, 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