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

FORM 10-K

(Mark One)

☑ **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

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1201 Lake Robbins Drive, The Woodlands, Texas	**77380-1046**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(832) 636-1000**

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 $0.10 per share	New York Stock Exchange
7.50% Tangible Equity Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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

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 ☐ No ☑

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 ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 ☑ No ☐

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 the 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. ☑

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 ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

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. ☐

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

The aggregate market value of the Company's common stock held by non-affiliates of the registrant on June 30, 2017, was $25.2 billion based on the closing price as reported on the New York Stock Exchange.

The number of shares outstanding of the Company's common stock at February 8, 2018, is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	532,487,194

Documents Incorporated By Reference

Portions of the Definitive Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 15, 2018 (to be filed with the Securities and Exchange Commission prior to April 5, 2018), are incorporated by reference into Part III of this Form 10-K.

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COMMONLY USED TERMS AND DEFINITIONS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. In addition, the following Company or industry-specific terms and abbreviations are used throughout this report:

$3.0 Billion Share-Repurchase Program - A program approved by the Anadarko Board of Directors, in September 2017, authorizing the repurchase of $2.5 billion of Anadarko's common stock, which was expanded to $3.0 billion in February 2018. The program extends through the end of 2018.

364-Day Facility - Anadarko's $2.0 billion 364-day senior unsecured RCF

3D - Three-dimensional

$5.0 Billion Facility - Anadarko's $5.0 billion senior secured RCF, which was replaced in January 2015 with the APC RCF and a 364-day facility

APC RCF - Anadarko's $3.0 billion senior unsecured RCF

AROs - Asset retirement obligations

ASR Agreement - An accelerated share-repurchase agreement with an investment bank to repurchase the Company's common stock

ASU - Accounting Standards Update

Bbl - Barrel

Bcf - Billion cubic feet

BOE - Barrels of oil equivalent

CBM - Coalbed methane

COSF - Centralized oil stabilization facility

DBJV - Delaware Basin JV Gathering LLC

DBJV System - A gathering system and related facilities located in the Delaware basin in Loving, Ward, Winkler, and Reeves Counties in West Texas

DBM Complex - The processing plants, gas gathering system, and related facilities and equipment in West Texas that serve production from Reeves, Loving, and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico

DD&A - Depreciation, depletion, and amortization

EOR - Enhanced oil recovery

EPA - U.S. Environmental Protection Agency

FASB - Financial Accounting Standards Board

FID - Final investment decision

Fitch - Fitch Ratings

FPSO - Floating production, storage, and offloading unit

G&A - General and administrative expenses

GAAP - U.S. Generally Accepted Accounting Principles

GOM Acquisition - The acquisition of oil and natural-gas assets in the Gulf of Mexico that closed on December 15, 2016

IPO - Initial public offering

IRS - U.S. Internal Revenue Service

LIBOR - London Interbank Offered Rate

LNG - Liquefied natural gas

MBbls/d - Thousand barrels per day

MBOE/d - Thousand barrels of oil equivalent per day

Mcf - Thousand cubic feet

MMBbls - Million barrels

MMBOE - Million barrels of oil equivalent

MMBtu - Million British thermal units

MMBtu/d - Million British thermal units per day

MMcf/d - Million cubic feet per day

Moody's - Moody's Investors Service

MTPA - Million tonnes per annum

NGLs - Natural gas liquids

NM - Not meaningful

NTSB - National Transportation Safety Board

NYMEX - New York Mercantile Exchange

Oil - Includes crude oil and condensate

OPEC - Organization of the Petroleum Exporting Countries

PUD or PUDs - Proved undeveloped reserves

RCF - Revolving credit facility

ROTF - Regional oil treating facility

SEC - U.S. Securities and Exchange Commission

S&P - Standard and Poor's

Sonatrach - The national oil and gas company of Algeria

Tax Reform Legislation - The U.S. Tax Cuts and Jobs Act signed into law on December 22, 2017

Tcf - Trillion cubic feet

TEN - Tweneboa/Enyenra/Ntomme

TEU or TEUs - Tangible equity units

Tronox - Tronox Incorporated

TSR - Total shareholder return

UOP - Unit-of-production

VIE or VIEs - Variable interest entity

WES - Western Gas Partners, LP, a publicly traded limited partnership, which is a consolidated subsidiary of Anadarko

WES RCF - WES's $1.2 billion senior unsecured RCF

WTI - West Texas Intermediate

WGEH - Western Gas Equity Holdings, LLC, the general partner of WGP

WGH - Western Gas Holdings, LLC, the general partner of WES

WGP - Western Gas Equity Partners, LP, a publicly traded limited partnership, which is a consolidated subsidiary of Anadarko

WGP RCF - WGP's $250 million three-year senior secured RCF

Zero Coupons - Anadarko's Zero-Coupon Senior Notes due 2036

PART I

Items 1 and 2. Business and Properties

GENERAL

Anadarko Petroleum Corporation is among the world's largest independent exploration and production companies, with approximately 1.4 billion BOE of proved reserves at December 31, 2017. Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by developing, acquiring, and exploring for oil and natural-gas resources vital to the world's health and welfare. Anadarko's asset portfolio is positioned to deliver long-term value to stakeholders by combining a large inventory of development opportunities in the U.S. onshore and the Gulf of Mexico with high-potential worldwide exploration and development activities.

Anadarko's portfolio includes assets in the Delaware and DJ basins in the U.S. onshore. The Company is also among the largest independent producers in the deepwater Gulf of Mexico and has exploration and production activities internationally, including activities in Algeria, Ghana, Mozambique, and other countries.

Anadarko's strategy is to explore for, develop and commercialize resources globally; ensure health, safety, and environmental excellence; and focus on financial discipline, flexibility, and value creation, while demonstrating the Company's core values of integrity and trust, servant leadership, people and passion, commercial focus, and open communication in all business activities.

Anadarko previously presented three reportable segments in its quarterly and annual filings: Oil and Gas Exploration and Production, Midstream, and Marketing. In the first half of 2017, Anadarko substantially completed a repositioning of its asset portfolio to focus on higher-margin liquids production. This shift resulted in a substantial decrease in the number of U.S. operating areas. Since the portfolio repositioning, the chief operating decision maker has reviewed operating results for Exploration and Production and Midstream when making operating and capital allocation decisions. Accordingly, Anadarko no longer identifies marketing activities as a separate reportable segment. Also, in prior periods, the Company aggregated its two midstream operating segments, WES Midstream and Other Midstream, into one Midstream reporting segment due to similar financial and operating characteristics. While the aggregation criteria continues to be met, the Company will no longer aggregate these operating segments in order to provide additional information about its midstream operations. Accordingly, Anadarko now has three reporting segments: Exploration and Production, WES Midstream, and Other Midstream, which include their respective marketing results.

Exploration and Production—This segment is engaged in the exploration, development, production, and sale of oil, natural gas, and NGLs and in advancing its Mozambique LNG project toward FID.

WES Midstream and Other Midstream—These two segments engage in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production as well as gathering and disposal of produced water. The WES Midstream segment consists of Western Gas Partners, LP, a publicly traded limited partnership, which is a consolidated subsidiary of Anadarko. The Other Midstream segment consists of the Company's other midstream assets.

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates, and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See *Risk Factors* under Item 1A of this Form 10-K.

Available Information The Company's corporate headquarters is located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046, and its telephone number is (832) 636-1000. The Company files or furnishes Annual Reports on Form 10-K; Quarterly Reports on Form 10-Q; Current Reports on Form 8-K; registration statements, or any amendments thereto; and other reports and filings with the SEC. Anadarko provides access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing, on its website located at investors.anadarko.com/sec-filings. The Company will also make available to any stockholder, without charge, printed copies of its Annual Report on Form 10-K as filed with the SEC. For copies of this Form 10-K, or any other filing, please contact Anadarko Petroleum Corporation, Investor Relations, P.O. Box 1330, Houston, Texas 77251-1330; call (855) 820-6605; send an email to investor@anadarko.com; or complete an information request on the Company's website at www.anadarko.com by selecting Investors/Shareholder Resources/Shareholder Services.

The public may read and copy any materials Anadarko files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers, including Anadarko, that file electronically with the SEC.

EXPLORATION AND PRODUCTION PROPERTIES AND ACTIVITIES

The Company's Exploration and Production segment actively manages Anadarko's worldwide oil, natural-gas, and NGLs sales of its equity production, as well as the Company's anticipated LNG sales. In marketing its production, the Company attempts to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. The Company's sales of oil, natural gas, and NGLs are generally made at market prices at the time of sale.

The Company sells its products under a variety of contract structures, including indexed, fixed-price, and cost-escalation-based agreements. The Company also engages in limited trading activities for the purpose of generating profits from exposure to changes in market prices of oil, natural gas, and NGLs. The Company does not engage in market-making practices and limits its marketing activities to oil, natural-gas, NGLs, and LNG commodity contracts. The Company's marketing-risk position is typically a net short position (reflecting agreements to sell oil, natural gas, and NGLs in the future for specific prices) that is offset by the Company's natural long position as a producer (reflecting ownership of underlying oil and natural-gas reserves). See *Commodity-Price Risk* under Item 7A of this Form 10-K.

Oil and NGLs Anadarko's oil and NGLs revenues are derived from production in the United States, Algeria, and Ghana. Most of the Company's U.S. oil and NGLs production is sold under contracts with prices based on market indices, adjusted for location, quality, and transportation. Product from Algeria is sold by tanker as Saharan Blend, Algerian condensate, refrigerated propane, and refrigerated butane to customers primarily in the Mediterranean and Western European area. Oil from Ghana is sold by tanker as Jubilee crude oil and TEN Blend crude oil to customers around the world. Saharan Blend, Jubilee, and TEN Blend are high-quality crudes that provide refiners with large quantities of premium products such as gasoline, diesel, and jet fuel.

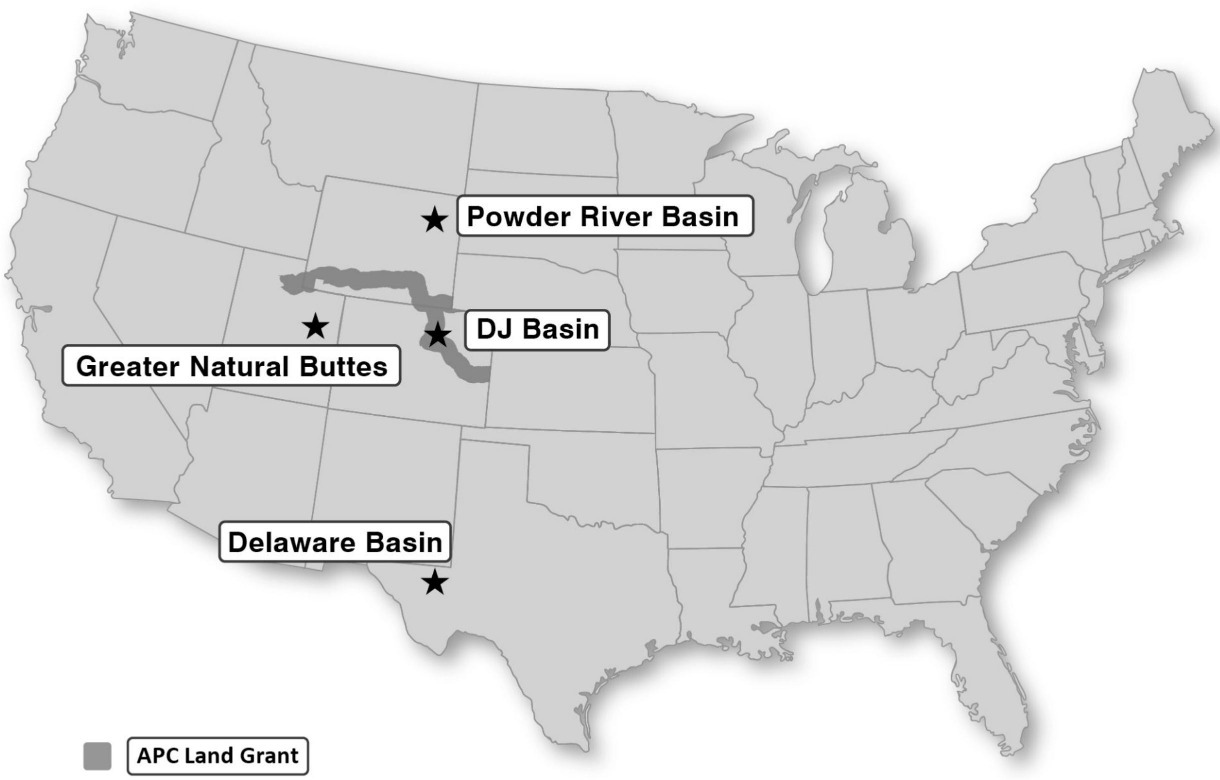
Natural Gas Anadarko markets its U.S. natural-gas production to maximize value and to reduce the inherent risks of physical commodity markets. The Company controls natural-gas firm-transportation capacity that ensures access to downstream markets, which enables the Company to maximize its natural-gas production. This transportation capacity also provides the opportunity to capture incremental value when price differentials between physical locations exist. From time to time, the Company stores natural gas in contracted storage facilities to minimize operational disruptions to its ongoing operations and to take advantage of seasonal price differentials. Normally, the Company will have forward contracts in place (physical delivery or financial derivative instruments) to sell stored natural gas at a fixed price.

United States

Overview Anadarko's U.S. operations include oil and natural-gas exploration and production in the U.S. onshore and deepwater Gulf of Mexico. The Company's U.S. operations accounted for 86% of sales volumes and 80% of sales revenues during 2017 and 88% of proved reserves at year-end 2017.

U.S. Onshore Anadarko's U.S. onshore properties include significant oil and natural-gas plays located in Colorado, Texas, Utah, and Wyoming, where the Company operates approximately 9,250 wells and owns interests in approximately 2,500 nonoperated wells.

The map below illustrates the locations of Anadarko's U.S. onshore oil and natural-gas exploration and production operations:



Activities in the U.S. onshore during 2017 primarily focused on adding reserves through horizontal drilling, optimizing wellbore and completion design, improving cost structure, and delivering efficient production. The Company also focused on capturing operatorship within its premier position in the Delaware basin. Process improvements and optimization projects assisted in providing both well performance and cycle-time improvements across all assets. The Company drilled 541 wells and completed 396 wells in the U.S. onshore during 2017. The Company also divested non-core U.S. onshore assets, primarily in South Texas, Southeast Texas, Pennsylvania, Wyoming, and Utah. In 2018, the Company expects to continue its horizontal drilling program, focusing on the Delaware and DJ basins.

The Company also has fee ownership of mineral rights, known as the Land Grant, under approximately eight million acres that pass through Colorado and Wyoming and into Utah. Management considers the Land Grant a significant competitive advantage for Anadarko as it enhances the Company's economic returns from production, offers drilling opportunities for the Company without expiration, and allows the Company to capture royalty revenue from third-party activity on Land Grant acreage.

Delaware Basin Anadarko holds interests in approximately 590,000 gross (240,000 net) acres in the Delaware basin in West Texas. Anadarko's 2017 drilling activity primarily targeted the Wolfcamp shale play, while also testing the liquids-rich Bone Spring tight sands and Avalon shale play. In 2017, Anadarko drilled 192 operated wells and participated in 93 nonoperated wells. The Company was focused on increasing operatorship through the drilling program for the majority of the year, averaging 14 operated drilling rigs through the third quarter of 2017 and ending 2017 with 10 operated drilling rigs. Prior to the conclusion of a participation agreement in July 2017, Anadarko completed all of the well proposals required to secure operatorship on approximately 70% of its joint venture acreage. Additionally, joint-operating agreements have been established in all areas where operatorship has been defined. The wells associated with operatorship capture are scheduled to be completed and turned to sales throughout 2018. During 2018, the Company plans to average seven operated rigs and six completion crews and grow year-over-year sales volumes by more than 50%.

The successful Wolfcamp shale delineation program continues to deliver encouraging results across the majority of Anadarko's acreage position. Anadarko is testing multiple zones within the Wolfcamp shale and several development concepts for increased efficiency. Included in these development concepts are multi-well pads, extended laterals, enhanced completion designs, and horizontal-well spacing. The Company has identified approximately 5,500 potential mid-lateral-equivalent drilling locations in the Wolfcamp A formation that are expected to provide substantial opportunity for Anadarko's future activity in the basin. The Company plans to continue to add significant infrastructure to facilitate future growth from this asset as discussed in *Midstream Properties and Activities*.

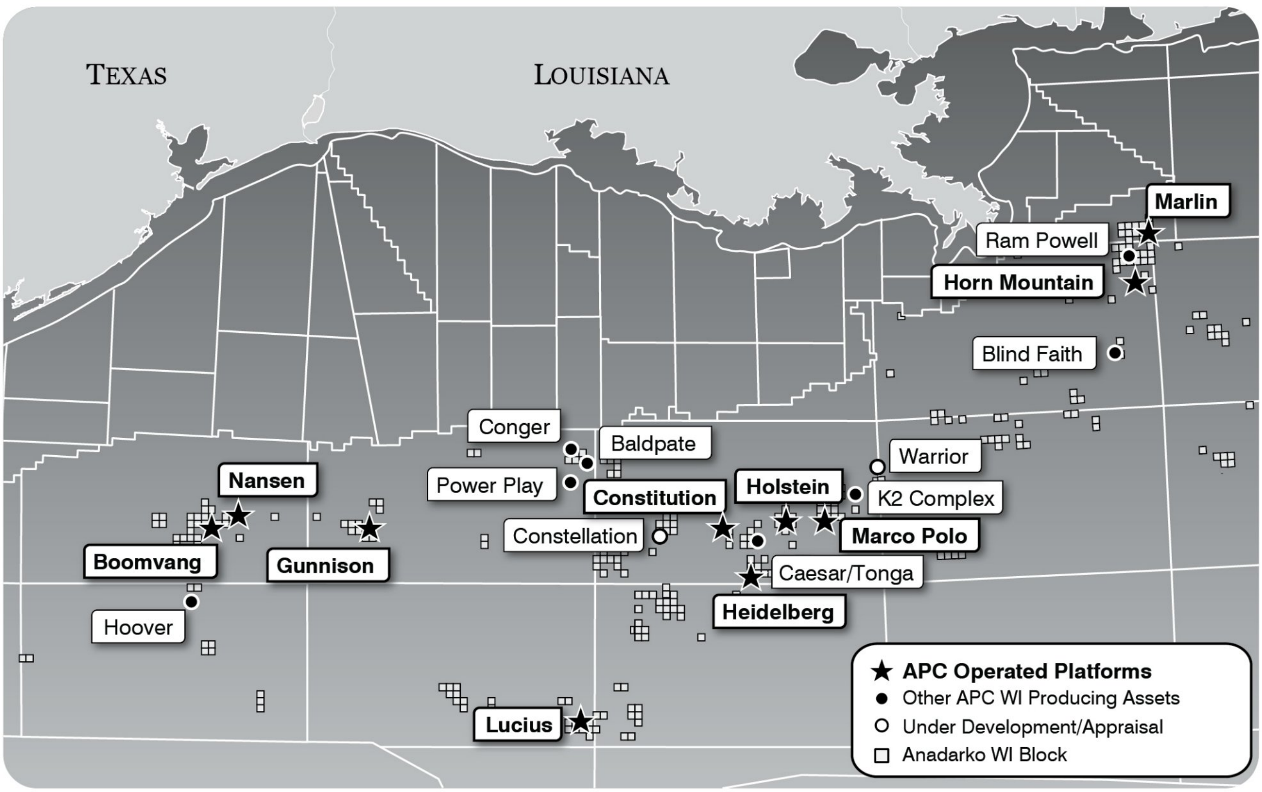
DJ Basin Anadarko holds interests in over 400,000 net acres in its core position and operates over 4,600 vertical wells and 1,400 horizontal wells in the DJ basin in Colorado. The field contains the Niobrara and Codell formations, which are naturally fractured formations that hold both liquids and natural gas. During 2017, the Company's drilling program focused entirely on horizontal development, drilling 348 horizontal wells. Horizontal drilling results in the field continue to be strong, with economics that are enhanced by the Company's ownership of the Land Grant and recent operational efficiencies in drilling and completions. In 2017, the Company implemented a new completion design, which has resulted in a 20% improvement in average well recovery. In the third quarter of 2017, the Company sanctioned the Latham plant, which is expected to provide an additional 400 MMcf/d in cryogenic processing.

Drilling spud-to-rig-release cycle time average for a mid-lateral equivalent well improved from 5.7 days in 2016 to 5.1 days in 2017. The full-year 2017 average drilling cost per foot was reduced by approximately 19% and completion capital was reduced by 11% relative to 2016. Operated well capital costs in 2017 decreased to less than $2.9 million from approximately $3.5 million in 2016 for a mid-lateral-equivalent well, driven by continued operational efficiencies and supply-chain savings. The Company had six operated drilling rigs in the first quarter of 2017 and ended 2017 with six operated drilling rigs. Anadarko expects to increase year-over-year oil sales volumes from the DJ Basin by more than 30% and plans to average five operated rigs and three completion crews in the basin during 2018.

Greater Natural Buttes The Greater Natural Buttes area in eastern Utah is a tight-gas asset. The Company uses cryogenic and refrigeration processing facilities in this area to extract NGLs from the natural-gas stream. The Company operated the field at a reduced activity level for the majority of 2017 due to capital being allocated to higher-margin projects. Focus in the field shifted to increasing operating margins through the reduction of expenses and optimization of base production. The Company operates approximately 2,850 wells in the area.

Gulf of Mexico Anadarko owns a working interest in 319 blocks in the Gulf of Mexico, operates 10 active floating platforms, and holds interests in 37 fields. The Company continued an active deepwater development and appraisal program in the Gulf of Mexico during 2017 as it continues to take advantage of existing infrastructure to cost-effectively develop known resources.

The map below illustrates the locations of Anadarko's Gulf of Mexico oil and natural-gas exploration and production operations:



Development

Horn Mountain At Horn Mountain (100% working interest), the Company is successfully executing on its tie-back strategy. The first development well from the GOM Acquisition was drilled in the first quarter of 2017. The well encountered more than 70 net feet of oil pay in the prolific Miocene sands and was tied back to the Horn Mountain facility. The well was completed and brought online in the second quarter of 2017. The second development well was drilled in the third quarter of 2017 and encountered 120 feet of high-quality oil pay. The well was tested in two Miocene sands and brought online in the first of these sands during the third quarter of 2017. These wells were drilled and brought to first production in approximately 110 days for the first well and approximately 80 days for the second well. A third well was drilled in the fourth quarter of 2017 and encountered 42 feet of high-quality oil pay with favorable structural position and good connectivity to existing wells. Completion and first production are expected in the first half of 2018. Additional drilling around the Horn Mountain facility is scheduled in 2018.

Marlin At Marlin (100% working interest), the Company successfully drilled a tie-back development well in the King field in the third quarter of 2017. The well encountered 134 feet of high-quality oil pay in three separate Miocene zones. The well was completed in three sands and had a successful flow test. First production is anticipated in the first quarter of 2018.

Lucius At Lucius (48.9% working interest), the Company successfully drilled and completed the eighth development well during 2017. The well encountered 217 net feet of oil pay in the primary objective Miocene sands and was brought online in the third quarter of 2017. The field continues to demonstrate favorable connectivity and strong aquifer support and is maintaining strong well deliverability. The Company entered into an agreement with partners to expand the Lucius unit to encompass the adjacent Hadrian North discovery in late 2017. The project was sanctioned and development of this tie-back opportunity commenced in 2018, with first production expected in 2019. The initial development phase is targeting high-quality Pliocene reservoir sands with similar rock and fluid properties as the Lucius producing wells.

Constitution Spar At the Constitution Spar (100% working interest), the Company completed planned maintenance that was designed to improve future uptime, further enhance safety, and facilitate the tieback of Constellation for first production.

Caesar/Tonga At Caesar/Tonga (33.75% working interest), the Company spud the eighth development well during the fourth quarter of 2017 and anticipates first production in the second quarter of 2018, when the well is tied back to Anadarko’s Constitution spar.

Constellation At Constellation (33.33% working interest), the Company successfully drilled and completed the first development well in the second quarter of 2017. The well encountered more than 120 feet of net oil pay and had a strong flow test. First production is expected in late 2018 or early 2019, when the well is tied back to Anadarko’s Constitution spar.

K2 Complex At the K2 Complex (41.8% working interest), the GC 562#6 development well, drilled and completed in 2016, was brought online in the second quarter of 2017. With the completion of this well, the field reached a nine-year production high of 38 MBOE/d.

Heidelberg At Heidelberg (44% working interest), the GC 859 #5 ST1 well encountered 216 net feet of oil pay and became the field’s fifth producing well in the first quarter of 2017.

Holstein At Holstein (100% working interest), the Company certified the permanently installed platform drilling rig and initiated a four-well drilling program in the fourth quarter of 2017. These wells are anticipated to be brought online during 2018.

Exploration and Appraisal

Warrior The Warrior exploration well (70% working interest) encountered more than 210 net feet of oil pay in multiple high-quality Miocene-aged reservoirs. The first Warrior appraisal well and subsequent side track completed drilling in the northern portion of the field in the third quarter of 2017. The well encountered approximately 109 net feet of dispersed oil pay. Despite finding oil, this northern appraisal well found insufficient quantities of oil pay to justify the development of the northern portion of the field in the current price environment. Evaluation of tie-back opportunities in the southern portion of the field is ongoing.

Calpurnia The Calpurnia exploration well (76% working interest), located near the Anadarko-operated Caesar/Tonga, Heidelberg and Holstein fields, finished drilling during the first quarter of 2017. The well encountered approximately 20 feet of net oil pay on water in a well-developed Miocene-aged sand. The well was subsequently sidetracked updip where it found nearly 60 net feet of oil pay. The wellbore was temporarily abandoned and is expected to be utilized for future production as a tieback to one of the Company’s nearby operated facilities.

Shenandoah The Shenandoah-6 appraisal well and subsequent sidetrack (33% working interest), which completed appraisal activities in April 2017, did not encounter oil in the eastern portion of the field. Given the results of this well and the commodity-price environment, the Company suspended further appraisal activities.

Phobos The first Phobos appraisal well (100% working interest), drilled in the first quarter of 2017, encountered approximately 130 net feet of oil pay from the primary objective Wilcox-aged reservoirs and more than 90 net feet of oil pay in the secondary objective Pliocene-aged reservoir. The second appraisal well, drilled in the third quarter of 2017, encountered approximately 136 net feet of oil pay from the primary objective Wilcox-aged reservoirs. These wells found insufficient quantities of oil pay to justify development in the current price environment.

Alaska Anadarko’s nonoperated (22% working interest) oil production and development activity in Alaska is concentrated on the North Slope. Net production from the Colville River Unit averaged approximately 11 MBbls/d of oil during the fourth quarter of 2017. The operator completed an active drilling campaign in 2017, which included seven development wells. Subsequent to year end, the Company divested its nonoperated interest in Alaska for net proceeds of $383 million. The transaction is subject to regulatory approval.

International

Overview Anadarko's international operations include oil, natural-gas, and NGLs production and development in Algeria and Ghana, along with activities in Mozambique, where the Company continues to make progress toward FID on an LNG development. The Company also has exploration acreage in Colombia, Mozambique, and other countries. International locations accounted for 14% of Anadarko's sales volumes and 20% of sales revenues during 2017 and 12% of proved reserves at year-end 2017. In 2018, the Company expects to focus its drilling activity in Ghana and continue preparing the site of the future onshore LNG park in Mozambique.

Algeria Anadarko is engaged in production and development operations in Algeria's Sahara Desert in Blocks 404 and 208, which are governed by a Production Sharing Agreement (PSA) between Anadarko, Sonatrach, and other partners. Under this PSA, the Company is responsible for 24.5% of the development and production costs. The Company produces oil through the Hassi Berkine South and Ourhoud central processing facilities (CPFs) in Block 404 and oil and NGLs through the El Merk CPF in Block 208. Gross production through these facilities averaged more than 337 MBbls/d in 2017, inclusive of approximately 34 days of planned downtime for statutory maintenance at the El Merk CPF. The Company drilled seven development wells in 2017. Late in 2017, Algeria and other members of OPEC agreed to extend the previously agreed upon reduction in production output through the end of 2018. Anadarko had minimal production impact from this reduction during 2017 and expects minimal impact in 2018.

Ghana Anadarko's production and development activities in Ghana are located offshore in the West Cape Three Points Block and the Deepwater Tano Block.

The Jubilee field (27% nonoperated participating interest), which spans both the West Cape Three Points Block and the Deepwater Tano Block, averaged gross production of 89 MBbls/d of oil in 2017. An average of 86 MMcf/d of natural gas was exported to an onshore natural-gas processing plant in satisfaction of a commitment established in conjunction with the Jubilee development plan. In October 2017, the partnership received Ghanaian government approval for the full-field plan of development, with drilling operations expected to commence in 2018.

In 2016, the operator of the Jubilee field announced that damage to the FPSO turret bearing had occurred. As a result, new production and offtake procedures were implemented, and the partners agreed to a long-term solution to convert the FPSO to a permanently spread-moored facility. Interim spread mooring of the FPSO commenced in the fourth quarter of 2016 and was completed during the first quarter of 2017. In early 2018, the operator will start the first of three shutdown periods that are expected to occur in 2018 to effectively stabilize the turret and rotate the FPSO to its permanent heading. In October, the partnership received Ghanaian Government approval for the full-field plan of development, with drilling operations expected to commence in 2018. Including the impact of the potential facility shutdown, the operator expects the average gross production from the Jubilee field to be more than 75 MBbls/d in 2018.

The TEN project (19% nonoperated participating interest), located in the Deepwater Tano Block, uses an 80 MBbls/d-capacity FPSO for production from subsea wells. After achieving first oil in the third quarter of 2016 and first liftings during the fourth quarter of 2016, the project averaged gross production of 56 MBbls/d of oil in 2017. The International Tribunal for the Law of the Sea issued a ruling in September 2017 regarding the delimitation of the maritime boundary between Ghana and Côte d'Ivoire in the Atlantic Ocean. The new maritime boundary, as determined by the tribunal, does not affect the TEN fields, and the operator now plans to resume development drilling in 2018.

Mozambique Anadarko operates Offshore Area 1 (26.5% working interest), which totals approximately 1.2 million gross acres. With the delivery of the legal and contractual framework necessary for the development of LNG in Mozambique, the commencement of resettlement, and progress towards the delivery of project finance and long-term LNG sales contracts, the Company continues to advance the initial two-train Golfinho/Atum project toward FID.

Development Anadarko, its Area 1 co-venturers, and the Government of Mozambique completed the foundational legal and contractual framework required to support investment in the Company's onshore LNG project. Based on these project advances and the approved Resettlement Plan, the Company commenced resettlement activities during the fourth quarter of 2017. This will facilitate site preparation and position the onshore area for construction of the LNG facilities. Additionally, the Company continues to work with construction and installation contractors to finalize costs and contracts and identify opportunities to reduce execution risk once the project progresses to the construction phase. In 2017, Anadarko and its co-venturers reached agreement on the project's first long-term sales and purchase agreement (SPA) for 2.6 MTPA of LNG with PTT Public Company Limited (PTT), Thailand's national oil and gas company. The SPA is subject to the approval of the Government of Thailand. The Company continues to progress additional LNG long-term sales contracts and advance the project finance process. The Development Plan for the initial two-train Golfinho/Atum project is in the final stages of the Government of Mozambique's approval process.

Exploration In Offshore Area 1, the Company continues to interpret re-processed 3D seismic data covering the Orca, Tubarão, and Tubarão-Tigre discovery areas, in accordance with the appraisal program submitted to the Government of Mozambique.

Colombia Anadarko controls the exclusive rights to explore or conduct technical evaluation activities on six blocks totaling approximately 14 million gross acres. In the Grand Fuerte area, the COL 5 and Purple Angel blocks are operated at a 50% working interest. In 2017, Anadarko withdrew from the Fuerte Norte and Fuerte Sur blocks. In the Grand COL area, the COL 1, COL 2, COL 6, and COL 7 blocks are operated at a 100% working interest.

In Grand Fuerte, the Purple Angel-1 exploration well concluded drilling in the first quarter of 2017. The well encountered approximately 70 to 110 net feet of gas pay and confirmed a gas column greater than 1,700 feet. The well successfully tested objectives establishing pressure connectivity to Anadarko's 2015 play-opening Kronos discovery. The rig mobilized to the Gorgon prospect, also located in the Purple Angel Block, where it successfully tested an analogous structure along trend to the Kronos discovery. The Gorgon-1 well completed drilling in the second quarter and encountered approximately 260 to 350 net feet of gas pay. Whole cores were obtained at both wells to assess the potential deliverability of the primary reservoirs.

While evaluation of the Kronos and Gorgon discovery areas continue, all of the Company's suspended exploratory well costs related to wells in the Grand Fuerte area were expensed in 2017 due to insufficient progress on contractual and fiscal reforms needed for deepwater gas development. See *Note 6—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

In Grand COL, interpretations of the Esmeralda 3D seismic survey are ongoing. A sea floor sampling campaign was completed in the third quarter of 2017, which supports the potential presence of liquid hydrocarbons in Grand COL.

Côte d'Ivoire Appraisal and exploration activity continued in 2017. The Paon-6A appraisal well, an up-dip appraisal of the South Channel, completed drilling in the third quarter of 2017 and did not encounter hydrocarbons. The Colibri-1X exploration well completed drilling in the third quarter of 2017 and encountered non-commercial quantities of hydrocarbons. During the fourth quarter of 2017, after further evaluation of the recent well results, the Company withdrew from all blocks in Côte d'Ivoire.

Other Anadarko also holds exploration interests in other offshore international areas, including Canada, South Africa, Gabon, Guyana, and Peru.

Proved Reserves

Estimates of proved reserves volumes owned at year end, net of third-party royalty interests, are presented in Bcf at a pressure base of 14.73 pounds per square inch for natural gas and in MMBbls for oil and NGLs. Total volumes are presented in MMBOE. For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volumes. Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year.

Disclosures by geographic area include the United States and International. For 2017, the International geographic area consisted of proved reserves located in Algeria and Ghana, which by country and in total represented less than 15% of the Company's total proved reserves.

Summary of Proved Reserves

	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBOE)
December 31, 2017				
Proved				
Developed				
United States	**361**	**2,640**	**176**	**977**
International	**136**	**24**	**10**	**150**
Undeveloped				
United States	**140**	**553**	**56**	**288**
International	**21**	**13**	**1**	**24**
Total proved	**658**	**3,230**	**243**	**1,439**
December 31, 2016				
Proved				
Developed				
United States	360	3,637	193	1,159
International	147	25	15	166
Undeveloped				
United States	181	762	75	383
International	14	—	—	14
Total proved	702	4,424	283	1,722
December 31, 2015				
Proved				
Developed				
United States	332	5,184	257	1,453
International	159	30	15	179
Undeveloped				
United States	193	807	68	396
International	29	—	—	29
Total proved	713	6,021	340	2,057

The Company's proved reserves product mix increased to 63% liquids in 2017, compared to 57% in 2016 and 52% in 2015. The Company's year-end 2017 proved reserves product mix was 46% oil, 37% natural gas, and 17% NGLs. This shift to liquids and the reduction in proved reserves was largely a result of divesting the Company's lower-margin, non-core assets throughout the last three years.

Changes to the Company's proved reserves during 2017 are summarized in the table below:

MMBOE	**2017**	2016	2015
Proved Reserves			
January 1	**1,722**	2,057	2,858
Reserves additions and revisions			
Discoveries and extensions	**114**	40	29
Infill-drilling additions (1)	**71**	69	89
Drilling-related reserves additions and revisions	**185**	109	118
Other non-price-related revisions (1)	**59**	191	289
Net organic reserves additions	**244**	300	407
Acquisition of proved reserves in place	**3**	97	1
Price-related revisions (1)	**92**	(147)	(624)
Total reserves additions and revisions	**339**	250	(216)
Sales in place	**(379)**	(294)	(279)
Production	**(243)**	(291)	(306)
December 31	**1,439**	1,722	2,057
Proved Developed Reserves			
January 1	**1,325**	1,632	1,969
December 31	**1,127**	1,325	1,632

(1) Combined and reported as revisions of prior estimates in the Company's *Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information)* under Item 8 of this Form 10-K. Reserves related to infill-drilling additions are treated as positive revisions. Price-related revisions reflect the impact of current prices on the reserves balance at the beginning of each year. Other non-price-related revisions reflect the net change of performance and cost updates, updates to development plans, and all other year-end updates.

Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year. The average prices used to compute proved reserves at December 31, 2017 were $51.34 per Bbl for oil, $2.98 per MMBtu for natural gas, and $31.83 per Bbl for NGLs.

The Company's estimates of proved developed reserves, PUDs, and total proved reserves at December 31, 2017, 2016, and 2015, and changes in proved reserves during the last three years are presented in the *Supplemental Information* under Item 8 of this Form 10-K. Also presented in the *Supplemental Information* are the Company's estimates of future net cash flows and discounted future net cash flows from proved reserves. See *Critical Accounting Estimates* under Item 7 of this Form 10-K for additional information on the Company's proved reserves.

The Company has not yet filed information with a federal authority or agency with respect to its estimated total proved reserves at December 31, 2017. Annually, Anadarko reports gross proved reserves for U.S.-operated properties to the U.S. Department of Energy. These reported reserves are derived from the same database used to estimate and report proved reserves in this Form 10-K.

Changes in PUDs Changes to PUDs during 2017 are summarized in the table below. The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUD development within five years unless specific circumstances warrant a longer development time horizon.

MMBOE	
PUDs at January 1, 2017	**397**
Revisions of prior estimates	**103**
Extensions, discoveries, and other additions	**22**
Conversions to developed	**(132)**
Purchases	**1**
Sales	**(79)**
PUDs at December 31, 2017	**312**

Revisions Revisions of prior estimates reflect Anadarko's ongoing evaluation of its asset portfolio. In 2017, PUDs were revised upward by 103 MMBOE.

MMBOE	**December 31, 2017**
Revisions due to changes in year-end prices (price impact to opening balance)	**—**
Other revisions of prior estimates	
Revisions due to performance	**32**
Revisions due to cost updates	**—**
Revisions due to successful infill drilling	**64**
Revisions due to development plan updates	**7**
Other revisions	**—**
Total other revisions of prior estimates	**103**
Revisions of prior estimates	**103**

Prior estimates were revised upward by a total of 103 MMBOE and were associated with the following:

- *Performance* The Company experienced an overall increase in PUDs of 32 MMBOE due to performance. Upward revisions of 39 MMBOE were driven primarily by performance improvements in the DJ and Delaware basin areas. Downward revisions of 7 MMBOE were primarily due to performance based reductions in various areas in the Gulf of Mexico.
- *Infill-drilling activities* The Company added 64 MMBOE of PUDs associated with infill-drilling activities, of which 46 MMBOE was in the DJ basin, 13 MMBOE in the Lucius and Holstein areas in the Gulf of Mexico and the remaining in the Ghana Jubilee field.
- *Development plan updates* The majority of revisions associated with updates to development plans occurred in the DJ basin due to ongoing optimization of development activity.

Extensions, discoveries, and other additions During 2017, PUDs increased by 22 MMBOE primarily through the extension of proved acreage. Projects in the Delaware basin, Alaska, Gulf of Mexico, and Ghana contributed to the increase.

Conversions In 2017, the Company converted 132 MMBOE of PUDs to developed status, equating to 31% of total year-end 2016 PUDs when adjusted for revisions and sales. Approximately 81% of PUD conversions occurred in U.S. onshore assets, including Alaska; 17% in Gulf of Mexico assets, and the remaining in international assets.

Anadarko spent $1.0 billion to develop PUDs in 2017, of which approximately 72% related to U.S. onshore assets, including Alaska; 26% related to Gulf of Mexico assets; and the remaining related to international assets.

Sales in place In 2017, PUDs decreased by 79 MMBOE due to the Company's divestiture activities in the Eagleford and Marcellus areas.

Development Plans The Company annually reviews all PUDs to ensure an appropriate plan for development exists. Typically, U.S. onshore PUDs are converted to developed reserves within five years of the initial proved reserves booking, but projects associated with arctic development, deepwater development, and international programs may take longer. At December 31, 2017, the Company had no material pre-2013 PUDs that remained undeveloped. However, the Company did have 19 MMBOE of PUDs scheduled to be developed more than five years from their initial date of booking. Approximately 12 MMBOE of these PUDs are associated with recompletion projects in the Gulf of Mexico, where project timing is dependent upon the current producing horizon achieving its economic limit. The remaining 7 MMBOE are primarily associated with international drilling projects, which are being developed according to government approved development plans. The Company did not have any U.S. onshore PUDs scheduled for development more than five years from initial booking.

Technologies Used in Proved Reserves Estimation The Company's 2017 proved reserves additions were based on estimates generated through the integration of relevant geological, engineering, and production data, using technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data used also included subsurface information obtained through indirect measurements such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate.

Internal Controls over Reserves Estimation Anadarko's estimates of proved reserves and associated future net cash flows were made solely by the Company's engineers and are the responsibility of management. The Company requires that reserves estimates be made by qualified reserves estimators (QREs) as defined by the Society of Petroleum Engineers' standards. The QREs are assigned to specific assets within the Company's regions. The QREs interact with engineering, land, and geoscience personnel to obtain the necessary data for projecting future production, net cash flows, and ultimate recoverable reserves. Management within each region approves the QREs' reserves estimates. All QREs receive ongoing education on the fundamentals of SEC definitions and reserves reporting through the Company's reserves manual and internal training programs administered by the Corporate Reserves Group (CRG).

The CRG ensures confidence in the Company's reserves estimates by maintaining internal policies for estimating and recording reserves in compliance with applicable SEC definitions and guidance. Compliance with the SEC reserves guidelines is the primary responsibility of Anadarko's CRG.

The CRG is managed through the Company's finance department, which is separate from its operating regions, and is responsible for overseeing internal reserves reviews and approving the Company's reserves estimates. The Director of Corporate Reserves manages the CRG and reports to the VP—Corporate Planning. The VP—Corporate Planning reports to the Company's Executive Vice President, Finance and Chief Financial Officer, who in turn reports to the Chairman, President, and Chief Executive Officer. The Governance and Risk Committee of the Company's Board meets with management, members of the CRG, and the Company's independent petroleum consultants, Miller and Lents, Ltd. (M&L), to discuss the results of procedures and methods reviews as discussed below as well as other matters and policies related to reserves.

The Company's principal engineer, who is primarily responsible for overseeing the preparation of proved reserves estimates, has over 31 years of experience in the oil and gas industry, including over 17 years as either a reserves estimator or manager. His further professional qualifications include a degree in petroleum engineering, extensive internal and external reserves training, and asset evaluation and management. The principal engineer is a member of the Society of Petroleum Engineers, where he has been a member for over 31 years, and is also a member of the Society of Petroleum Evaluation Engineers. In addition, he is an active participant in industry reserves seminars and professional industry groups.

Third-Party Procedures and Methods Reviews M&L reviewed the procedures and methods used by Anadarko's staff in preparing the Company's estimates of proved reserves and future net cash flows at December 31, 2017. The purpose of the review was to determine if the procedures and methods used by Anadarko to estimate its proved reserves are effective and in accordance with the definitions contained in SEC regulations. The procedures and methods reviews by M&L were limited reviews of Anadarko's procedures and methods and do not constitute a complete review, audit, independent estimate, or confirmation of the reasonableness of Anadarko's estimates of proved reserves and future net cash flows.

The reviews covered 11 fields that included major assets in the United States and Africa and encompassed approximately 92% of the Company's estimates of proved reserves and associated future net cash flows at December 31, 2017. In each review, Anadarko's technical staff presented M&L with an overview of the data, methods, and assumptions used in estimating its reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures, and relevant economic criteria.

Management's intent in retaining M&L to review its procedures and methods is to provide objective third-party input on the Company's procedures and methods and to gather industry information applicable to reserves estimation and reporting processes.

Sales Volumes, Prices, and Production Costs

The following provides the Company's annual sales volumes, average sales prices, and average production costs per BOE for each of the last three years:

	Sales Volumes				Average Sales Prices [1]			
	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Barrels of Oil Equivalent (MMBOE)	Oil (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)	Average Production Costs [2] (Per BOE)
2017								
United States								
DJ basin	**31**	**212**	**21**	**88**	**49.73**	**2.55**	**27.46**	**10.23**
Other United States	**66**	**266**	**13**	**123**	**49.57**	**3.03**	**32.24**	**9.38**
Total United States	**97**	**478**	**34**	**211**	**49.62**	**2.82**	**29.24**	**9.73**
International	**32**	**—**	**2**	**34**	**53.77**	**—**	**35.64**	**7.01**
Total	**129**	**478**	**36**	**245**	**50.66**	**2.82**	**29.54**	**9.34**
2016								
United States								
DJ basin	33	214	20	89	40.27	2.00	18.26	8.41
Other United States	52	552	24	168	38.29	2.06	20.21	6.80
Total United States	85	766	44	257	39.06	2.04	19.32	7.36
International	31	—	2	33	43.93	—	25.63	7.93
Total	116	766	46	290	40.34	2.04	19.64	7.42
2015								
United States								
DJ basin	35	176	16	81	44.88	2.31	15.65	8.21
Other United States	50	676	29	191	45.08	2.37	17.83	8.55
Total United States	85	852	45	272	45.00	2.36	17.03	8.45
International	31	—	2	33	51.68	—	29.85	7.22
Total	116	852	47	305	46.79	2.36	17.61	8.31

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.

Production costs are costs to operate and maintain the Company's wells, related equipment, and supporting facilities, including the cost of labor, well service and repair, location maintenance, power and fuel, gathering, processing, transportation, other taxes, and production-related G&A costs. Additional information on volumes, prices, and production costs is contained in *Financial Results* under Item 7 of this Form 10-K. Additional detail regarding production costs is contained in the *Supplemental Information* under Item 8 of this Form 10-K.

Delivery Commitments

The Company sells oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. At December 31, 2017, Anadarko was contractually committed to deliver approximately 1,488 Bcf of natural gas to various customers in the United States through 2032. These contracts have various expiration dates, with approximately 21% of the Company's current commitment to be delivered in 2018 and 76% by 2022. At December 31, 2017, Anadarko was also contractually committed to deliver approximately 22 MMBbls of oil to a customer in the United States through 2020. These contracts have various expiration dates, with approximately 45% of the Company's current commitment to be delivered in 2018 and 100% by 2020. At December 31, 2017, Anadarko also was contractually committed to deliver approximately 8 MMBbls of oil to ports in Algeria and Ghana through 2018. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves, which the Company regularly monitors to ensure sufficient availability to meet its commitments. If production is not sufficient to meet contractual delivery commitments, the Company may purchase commodities in the market to satisfy its delivery commitments. In areas where Anadarko no longer has production due to asset divestitures, the Company has entered into long-term purchase commitments to satisfy its existing delivery commitments.

Properties and Leases

The following shows the developed lease, undeveloped lease, and fee mineral acres in which Anadarko held interests at December 31, 2017:

	Developed Lease		Undeveloped Lease		Fee Mineral [1]		Total	
thousands of acres	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States								
Onshore	2,417	1,486	1,797	681	9,891	8,192	14,105	10,359
Offshore	352	198	1,483	1,098	—	—	1,835	1,296
Total United States	2,769	1,684	3,280	1,779	9,891	8,192	15,940	11,655
International	636	138	39,440	31,690	—	—	40,076	31,828
Total	3,405	1,822	42,720	33,469	9,891	8,192	56,016	43,483

(1) The Company's fee mineral acreage is primarily undeveloped.

At December 31, 2017, the Company had approximately 21 million net undeveloped lease acres scheduled to expire by December 31, 2018, if the Company does not establish production or take any other action to extend the terms. The net undeveloped lease acres scheduled to expire by December 31, 2018, if not amended, primarily relate to 20.5 million net acres of international exploration acreage in South Africa (16.0 million net acres) and Colombia (4.5 million net acres) where proved reserves have not yet been assigned. The Company plans to continue the terms of many of these licenses and concession areas through operational or administrative actions and does not expect a significant portion of its total net acreage position to expire in 2018.

Drilling Program

The Company's 2017 drilling program focused on proven and emerging liquids-rich basins in the United States (onshore and deepwater Gulf of Mexico) and various international locations. Exploration activity in 2017 consisted of 10 gross completed wells, which included 8 U.S. onshore wells and 2 Gulf of Mexico wells. Development activity in 2017 consisted of 554 gross completed wells, which included 548 U.S. onshore wells and 6 Gulf of Mexico wells.

Drilling Statistics

The following shows the number of oil and gas wells completed in each of the last three years:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2017							
United States	**6.6**	**3.6**	**10.2**	**359.1**	**2.4**	**361.5**	**371.7**
International	**—**	**7.3**	**7.3**	**—**	**—**	**—**	**7.3**
Total	**6.6**	**10.9**	**17.5**	**359.1**	**2.4**	**361.5**	**379.0**
2016							
United States	3.7	1.2	4.9	322.1	—	322.1	327.0
International	—	1.8	1.8	2.9	—	2.9	4.7
Total	3.7	3.0	6.7	325.0	—	325.0	331.7
2015							
United States	16.0	—	16.0	573.1	13.8	586.9	602.9
International	2.4	0.4	2.8	1.8	—	1.8	4.6
Total	18.4	0.4	18.8	574.9	13.8	588.7	607.5

The following shows the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion at December 31, 2017:

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion (1)	
	Exploration	Development	Exploration	Development (2)
United States				
Gross	—	23	14	543
Net	—	20.4	8.6	396.2
International				
Gross	—	—	28	15
Net	—	—	7.8	3.5
Total				
Gross	—	23	42	558
Net	—	20.4	16.4	399.7

(1) Wells suspended or waiting on completion include exploration and development wells where drilling has occurred, but the wells are awaiting the completion of hydraulic fracturing or other completion activities or the resumption of drilling in the future.

(2) There were 107 MMBOE of PUDs primarily assigned to U.S. onshore development wells suspended or waiting on completion at December 31, 2017. The Company expects to convert these reserves to developed status within five years of their initial disclosure.

Productive Wells

At December 31, 2017, the Company's ownership interest in productive wells was as follows:

	Oil Wells [1]	Gas Wells [1]
United States		
Gross	3,571	8,574
Net	2,309.2	7,182.0
International		
Gross	208	9
Net	37.3	2.2
Total		
Gross	3,779	8,583
Net	2,346.5	7,184.2

(1) Includes wells containing multiple completions as follows:

Gross	411	2,997
Net	355.1	2,697.1

MIDSTREAM PROPERTIES AND ACTIVITIES

Anadarko invests in and operates midstream (gathering, processing, treating, transportation, and produced-water disposal) assets to complement its operations in regions where the Company has oil and natural-gas production. Through ownership and operation of these facilities, the Company improves its ability to manage costs, controls the timing of bringing on new production, and enhances the value received for gathering, processing, treating, and transporting the Company's production. Anadarko's midstream business also provides services to third-party customers, including major and independent producers. Anadarko generates revenues from its midstream activities through a variety of contract structures, including fixed-fee, percent-of-proceeds, wellhead purchase, and keep-whole agreements. Anadarko's midstream activities include those of WES, which acquires, owns, develops, and operates midstream assets. At December 31, 2017, Anadarko's ownership interest in WGP consisted of an 81.6% limited partner interest and the entire non-economic general partner interest. At December 31, 2017, WGP's ownership interest in WES consisted of a 29.8% limited partner interest, the entire 1.5% general partner interest, and all of the WES incentive distribution rights. At December 31, 2017, Anadarko also owned a 9.1% limited partner interest in WES through other subsidiaries.

WES Midstream

At the end of 2017, WES Midstream included 20 gathering systems and 51 processing and treating facilities located throughout major onshore producing basins in Wyoming, Colorado, Utah, Pennsylvania, Texas, and New Mexico. In 2017, the WES Midstream activity was concentrated in the Delaware basin to build infrastructure for present and future Wolfcamp development. In 2018, the Company expects to continue to focus its midstream investment on the Delaware and DJ basins.

Delaware Basin In 2017, the Company expanded its midstream infrastructure for Bone Spring, Wolfcamp, and Avalon production in the Delaware basin of West Texas, installing over 150 miles of gas and water gathering lines. Four new central gathering facilities (CGFs) were installed and seven existing CGFs were expanded to add a total of approximately 495 MMcf/d of compression capacity. Two produced-water disposal systems were placed into service during the second quarter of 2017, with combined capacity of 90,000 barrels of water per day. Additional compressor station expansions within the field are planned for 2018.

In the first quarter of 2017, Anadarko completed the divestiture of its Marcellus operated and nonoperated oil and natural-gas assets and related operated midstream assets to a third party. The midstream assets owned by WES were excluded from the divestiture; however, during the first quarter of 2017, WES entered into a property exchange whereby it exchanged its 33.75% nonoperated interest in certain Marcellus assets, commonly referred to as the Liberty and Rome systems, plus $155 million in cash for a third party's 50% nonoperated interest in the DBJV System. The property exchange increased WES's interest in the DBJV System to 100%.

With the completion of Train VI, a 200 MMcf/d cryogenic facility, at the end of 2017, the DBM Complex now includes 900 MMcf/d of cryogenic processing capacity, 1,400 gallons per minute of amine-treating capacity, 18 MBbls/d of high-pressure condensate stabilization, and a rich-gas gathering system, with over 400 miles of high-pressure and low-pressure segments. Construction has begun on the Mentone plant, which will add 400 MMcf/d of cryogenic processing capacity and is expected to come online in 2018.

In December 2015, there was an initial fire and secondary explosion at the processing facility within the DBM Complex. The majority of damage was to the liquid-handling facilities and the amine-treating units at the inlet of the processing facility. Train II (with capacity of 100 MMcf/d) sustained the most damage of the processing trains and returned to service in December 2016. Train III (with capacity of 200 MMcf/d) experienced minimal damage and returned to full service in May 2016. There was no damage to Trains IV and V (each with a capacity of 200 MMcf/d), which were under construction at the time of the incident. Train IV came online in May 2016 and Train V came online in October 2016.

During the second quarter of 2017, the Company reached a settlement with insurers and final proceeds were received related to the December 2015 incident at the DBM Complex. As of December 31, 2017, the Company had received a total of $86.7 million in cash proceeds from insurers related to the incident, including $46.2 million in proceeds from business interruption insurance claims and $40.5 million in proceeds from property insurance claims.

DJ Basin The Company continued to optimize gathering and compression in 2017, which reduced gathering system pressures in the field, enhancing system efficiency and improving the base production profile. Management believes that the Company is well-positioned in the DJ basin with its oil and NGLs transportation capacity, which includes transport by pipeline, rail, and truck.

In 2017, the Company expanded its midstream infrastructure to support DJ basin production, adding a total of approximately 100 MMcf/d of compression capacity to three of its compressor stations. In the third quarter of 2017, the Company sanctioned the construction of the Latham plant consisting of two cryogenic processing trains, which will increase processing capacity by 400 MMcf/d. Construction is expected to start in 2018, and the plant is expected to be online in 2019. Additional compressor stations and expansions to existing compressor stations are also planned for 2018.

The Company elected to participate in an expansion of the White Cliffs oil pipeline, which was completed during 2017, increasing total capacity from 150 MBbls/d to approximately 180 MBbls/d.

Eagleford In the Eagleford shale, the Company continues to operate oil and gas gathering systems, with a 2017 average gross throughput of 55 MBbls/d of oil and 450 MMcf/d of natural gas. The 200 MMcf/d operated Brasada natural-gas cryogenic processing plant continued steady operations at capacity. In the first quarter of 2017, Anadarko completed the divestiture of its oil and natural-gas assets to a third party; the midstream assets owned by WES were not divested.

The following provides information regarding the WES Midstream assets including gathering, processing, treating, transportation, and produced-water disposal by area (excluding divestitures closed in 2017):

Area	Miles of Pipelines	Total Horsepower	2017 Average Net Throughput (MMcf/d)	2017 Average Net Throughput (MBbls/d)
DJ basin	4,680	319,200	950	50
Delaware basin	1,300	316,100	810	30
Greater Natural Buttes	40	74,900	420	10
Wyoming	4,750	173,300	800	—
Eagleford	870	200,100	450	30
Other	870	34,600	80	80
Total	12,510	1,118,200	3,510	200

Other Midstream

At the end of 2017, Anadarko's Other Midstream assets included 8 gathering systems and 20 processing and treating facilities located throughout major onshore producing basins in Colorado, Utah, Texas, and New Mexico. In 2017, Anadarko's Other Midstream activity was concentrated in the Delaware basin to build infrastructure for present and future Wolfcamp development. In 2018, the Company expects to continue to focus its midstream investment on the Delaware and DJ basins.

Delaware Basin In 2017, the Company expanded its midstream infrastructure for Bone Spring, Wolfcamp, and Avalon production in the Delaware basin of West Texas, installing over 60 miles of oil and water gathering lines. In addition, oil processing capacity increased by 20 MBbls/d in 2017 with the expansion of the Avalon central production facility in Loving County, and capacity is expected to increase significantly in 2018 with two ROTFs, each with capacity of 60 MBbls/d, expected to come online. Several new oil pumping stations and produced-water disposal facilities are also planned for 2018.

In the first quarter of 2017, Anadarko purchased an additional interest in the Bone Spring Plant from a third party, increasing its ownership in the plant from 33% to 50%.

DJ Basin In 2017, the Company completed certain projects at its COSF, increasing the facility's capacity from 100 MBbls/d to 125 MBbls/d. Construction has begun on a sixth stabilizer train at the COSF, which will add 25 MBbls/d of capacity.

The following provides information regarding Anadarko's Other Midstream assets including gathering, processing, treating, transportation, and produced-water disposal by area (excluding divestitures closed in 2017):

Area	Miles of Pipelines	Total Horsepower	2017 Average Net Throughput (MMcf/d)	2017 Average Net Throughput (MBbls/d)
DJ basin	1,050	50,200	190	110
Delaware basin	540	44,500	130	80
Greater Natural Buttes	1,180	152,100	330	—
Other	300	7,000	—	10
Total	3,070	253,800	650	200

COMPETITION

The oil and gas business is highly competitive in the exploration for and acquisition of reserves and in the gathering and marketing of oil and gas production. The Company's competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies as well as participants in other industries supplying energy and fuel to consumers.

SEGMENT INFORMATION

For additional information on operations by segment, see *Note 26—Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, and for additional information on risk associated with international operations, see *Risk Factors* under Item 1A of this Form 10-K.

EMPLOYEES

The Company had approximately 4,400 employees at December 31, 2017.

REGULATORY AND ENVIRONMENTAL MATTERS

Environmental and Occupational Health and Safety Regulations

Anadarko's business operations are subject to numerous international, provincial, federal, regional, state, tribal, local, and foreign environmental and occupational health and safety laws and regulations. The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- the U.S. Clean Air Act, which restricts the emission of air pollutants from many sources, imposes various pre-construction, monitoring, and reporting requirements, which the EPA has relied upon as authority for adopting climate change regulatory initiatives relating to greenhouse gas (GHG) emissions
- the U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act, which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States
- the U.S. Oil Pollution Act of 1990, which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in waters of the United States
- U.S. Department of the Interior regulations, which relate to offshore oil and natural-gas operations in U.S. waters and impose obligations for establishing financial assurances for decommissioning activities, liabilities for pollution cleanup costs resulting from operations, and potential liabilities for pollution damages
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur
- the U.S. Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes
- the U.S. Safe Drinking Water Act, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and control over the injection of waste fluids into below-ground formations that may adversely affect drinking water sources
- the U.S. Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories
- the U.S. Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas
- the National Environmental Policy Act, which requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment
- the U.S. Department of Transportation regulations, which relate to advancing the safe transportation of energy and hazardous materials and emergency response preparedness

These U.S. laws and regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. Moreover, multiple environmental laws provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. See *Risk Factors* under Item 1A of this Form 10-K for further discussion on hydraulic fracturing; ozone standards; induced seismicity regulatory developments; climate change, including methane or other GHG emissions; and other regulations relating to environmental protection. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards continue to evolve.

Many states where the Company operates also have, or are developing, similar environmental and occupational health and safety laws and regulations governing many of these same types of activities. In addition, many foreign countries where the Company is conducting business also have, or may be developing, regulatory initiatives or analogous controls that regulate Anadarko's environmental-related activities. While the legal requirements imposed under state or foreign law may be similar in form to U.S. laws and regulations, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the permitting, development, or expansion of a project or substantially increase the cost of doing business. In addition, environmental and occupational health and safety laws and regulations, including new or amended legal requirements that may arise in the future to address potential environmental concerns such as air and water impacts, are expected to continue to have a considerable impact on the Company's operations.

The Company has incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. Historically, the Company's environmental compliance costs have not had a material adverse effect on its results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on the Company's business and operation results. Although the Company is not fully insured against all environmental and occupational health and safety risks, and the Company's insurance does not cover any penalties or fines that may be issued by a governmental authority, it maintains insurance coverage that it believes is sufficient based on the Company's assessment of insurable risks and consistent with insurance coverage held by other similarly situated industry participants. Nevertheless, it is possible that other developments, such as stricter and more comprehensive environmental and occupational health and safety laws and regulations as well as claims for damages to property or persons or imposition of penalties resulting from the Company's operations, could have a material adverse effect on Anadarko and its results of operations.

Oil Spill-Response Plan

Domestically, the Company is subject to compliance with the federal Bureau of Safety and Environmental Enforcement (BSEE) regulations, which, among other standards, require every owner or operator of a U.S. offshore lease to prepare and submit for approval an oil spill-response plan prior to conducting any offshore operations. The submitted plan is required to provide a detailed description of actions to be taken in the event of a spill; identify contracted spill-response equipment, materials, and trained personnel; and stipulate the time necessary to deploy identified resources in the event of a spill. The BSEE regulations may be amended, resulting in more stringent requirements as changes to the amount and type of spill-response resources to which an owner or operator must maintain ready access. Accordingly, resources available to the Company may change to satisfy any new regulatory requirements or to adapt to changes in the Company's operations.

Anadarko has in place and maintains Oil Spill-Response Plans (Plans) for the Company's Gulf of Mexico operations. The Plans set forth procedures for rapid and effective responses to spill events that may occur as a result of Anadarko's operations. The Plans are reviewed by the Company at least annually and updated as necessary. Drills are conducted by the Company at least annually to test the effectiveness of the Plans and includes the participation of spill-response contractors and other third parties. The Plans and any revisions to the Plans must be approved by the BSEE.

As part of the Company's oil spill-response preparedness, and as set forth in the Plans, Anadarko maintains membership in Clean Gulf Associates (CGA) and has an employee representative on the executive committee of CGA. CGA was created to provide a means of effectively staging response equipment and to provide effective spill-response capability for its member companies operating in the Gulf of Mexico. Anadarko is also a member of the Marine Preservation Association, which provides full access to the Marine Spill Response Corporation (MSRC) cooperative. In the event of a spill, MSRC stands ready to mobilize all of its equipment and materials. MSRC has a fleet of dedicated Responder Class Oil Spill Response Vessels (OSRVs), designed and built to recover spilled oil.

The Company has also entered into a contractual commitment to access subsea intervention, containment, capture, and shut-in capacity for deepwater exploration wells. Marine Well Containment Company (MWCC) is open to oil and gas operators in the U.S. Gulf of Mexico and provides members access to oil spill-response equipment and services on a per-well fee basis. Anadarko has an employee representative on the executive committee of MWCC. MWCC members have access to a containment system that is planned for use in deepwater depths of up to 10,000 feet, with containment capacity of 100 MBbls/d of liquids and flare capability for 200 MMcf/d of natural gas.

Anadarko has emergency and oil spill-response plans in place for each of its exploration and operational activities around the globe. Each plan is intended to satisfy the requirements of relevant local or national authorities, describes the actions the Company is expected to take in the event of an incident, includes drills conducted by the Company at least annually, and includes reference to external resources that may become necessary in the event of an incident. Included in these external resources is the Company's contract with Oil Spill Response Limited (OSRL), a global emergency and oil spill-response organization headquartered in London.

In addition to Anadarko's membership in or access to CGA, MSRC, OSRL, and MWCC, the Company participates in industry-wide task forces, which are currently studying improvements in both gaining access to and controlling blowouts in subsea environments. Two such task forces are the Subsea Well Control and Containment Task Force and the Oil Spill Task Force.

TITLE TO PROPERTIES

As is customary in the oil and gas industry, a preliminary title review is conducted at the time properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, thorough title examinations of the drill site tracts are conducted by third-party attorneys, and curative work is performed with respect to significant defects, if any, before proceeding with operations. Anadarko believes the title to its leasehold properties is good, defensible, and customary with practices in the oil and gas industry, subject to such exceptions that, in the opinion of legal counsel for the Company, do not materially detract from the use of such properties.

Leasehold properties owned by the Company are subject to royalty, overriding royalty, and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements, current taxes, development obligations under oil and gas leases and other encumbrances, easements, and restrictions. Anadarko does not believe any of these burdens will materially interfere with its use of these properties.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age at January 31, 2018	Position
R. A. Walker	60	Chairman, President and Chief Executive Officer
Robert G. Gwin	54	Executive Vice President, Finance and Chief Financial Officer
Daniel E. Brown	42	Executive Vice President, U.S. Onshore Operations
Mitchell W. Ingram	55	Executive Vice President, International & Deepwater Operations and Project Management
Ernest A. Leyendecker	57	Executive Vice President, Exploration
Robert K. Reeves	60	Executive Vice President, Law and Chief Administrative Officer
Christopher O. Champion	48	Senior Vice President, Chief Accounting Officer and Controller

Mr. Walker was named Chairman of the Board of the Company in May 2013, in addition to the role of Chief Executive Officer and director, both of which he assumed in May 2012, and the role of President, which he assumed in February 2010. He previously served as Chief Operating Officer from March 2009 until his appointment as Chief Executive Officer. He served as Senior Vice President, Finance and Chief Financial Officer from September 2005 until March 2009. From August 2007 until March 2013, he served as director of WGH and served as its Chairman of the Board from August 2007 to September 2009. Mr. Walker served as a director of WGEH from September 2012 until March 2013. Mr. Walker served as a director of Temple-Inland Inc. from November 2008 to February 2012 and a director of CenterPoint Energy, Inc. from April 2010 to April 2015 and has served as a director of BOK Financial Corporation since April 2013, where he is the Chairman of the Risk Committee.

Mr. Gwin was named Executive Vice President, Finance and Chief Financial Officer in May 2013 and previously served as Senior Vice President, Finance and Chief Financial Officer since March 2009 and Senior Vice President since March 2008. He also has served as Chairman of the Board of WGH since October 2009 and as a director since August 2007. Additionally, Mr. Gwin has served as Chairman of the Board of WGEH since September 2012 and served as President of WGH from August 2007 to September 2009 and as Chief Executive Officer of WGH from August 2007 to January 2010. He joined Anadarko in January 2006 as Vice President, Finance and Treasurer and served in that capacity until March 2008. He has served as Chairman of the Board of LyondellBasell Industries N.V. since August 2013 and as a director since May 2011.

Mr. Brown was named Executive Vice President, U.S. Onshore Operations in October 2017. Prior to this position, he served as Executive Vice President, International and Deepwater Operations since May 2017; Senior Vice President, International and Deepwater Operations since August 2016; Vice President, Operations (Southern and Appalachia) since August 2013; and Vice President, Corporate Planning since May 2013. Mr. Brown joined Anadarko upon the acquisition of Kerr-McGee Corporation in August 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, where he began his career, including General Manager of the Maverick basin and the Company's Freestone/Chalk area, Business Advisor for Planning and Reserves Administration in the Gulf of Mexico, and in engineering positions in both the U.S. onshore and the Gulf of Mexico. Mr. Brown has served as a director of WGH and WGEH since November 2017.

Mr. Ingram was named Executive Vice President, International & Deepwater Operations and Project Management in October 2017. He joined the Company as Executive Vice President, Global LNG in November 2015. Prior to joining Anadarko, Mr. Ingram was with BG Group since 2006, where he served as a member of the Executive Committee in the role of Executive Vice President—Technical since March 2015. Previously, he held positions of increasing responsibility with the company's LNG project in Queensland, Australia, where he served as Managing Director of QGC, a BG Group business, since April 2014; as Deputy Managing Director since September 2013; and as Project Director of the Queensland Curtis LNG project since May 2012. From 2006 to May 2012, Mr. Ingram was Asset General Manager of BG Group's Karachaganak interest in Kazakhstan. He joined BG Group after 20 years with Occidental Oil & Gas, where he held several U.K. and international leadership positions in project management, development, and operations.

Mr. Leyendecker was named Executive Vice President, Exploration in October 2017. Prior to this position, he served as Executive Vice President, International and Deepwater Exploration since August 2016; Senior Vice President, International Exploration since April 2015; and Senior Vice President, Gulf of Mexico Exploration since February 2014. Prior to that, he served as Vice President, Gulf of Mexico Exploration since May 2011 and as Vice President of Corporate Planning and Gulf of Mexico Exploration since October 2010. Mr. Leyendecker joined Anadarko upon the acquisition of Kerr-McGee Corporation in August 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, including Exploration Manager for the Gulf of Mexico and General Manager for Worldwide Exploration, Engineering and Planning. Mr. Leyendecker began his career with Marathon Oil Company prior to pursuing a leadership role with Enterprise Oil Gulf of Mexico, which was acquired by Shell Oil in 2002.

Mr. Reeves was named Executive Vice President, Law and Chief Administrative Officer in September 2015 and previously served as Executive Vice President, General Counsel and Chief Administrative Officer since May 2013 and as Senior Vice President, General Counsel and Chief Administrative Officer since February 2007. He also served as Chief Compliance Officer from July 2012 to May 2013. He served as Corporate Secretary from February 2007 to August 2008. He previously served as Senior Vice President, Corporate Affairs & Law and Chief Governance Officer since 2004. Prior to joining Anadarko, he served as Executive Vice President, Administration and General Counsel of North Sea New Ventures from 2003 to 2004 and as Executive Vice President, General Counsel and Secretary of Ocean Energy, Inc. and its predecessor companies from 1997 to 2003. He served as a director of Key Energy Services, Inc., a publicly traded oilfield services company, from October 2007 to December 2016 and has served as a director of WGH since August 2007 and as a director of WGEH since September 2012.

Mr. Champion was named Senior Vice President, Chief Accounting Officer and Controller in February 2017. He joined the Company as Vice President, Chief Accounting Officer and Controller in June 2015. Prior to joining Anadarko, Mr. Champion was an Audit Partner with KPMG LLP since October 2003 and served as KPMG's National Audit Leader for Oil and Natural Gas since 2008. He began his career at Arthur Andersen LLP in 1992 before joining KPMG LLP in 2002 as a senior audit manager.

Officers of Anadarko are elected each year at the first meeting of the Board following the annual meeting of stockholders, the next of which is expected to occur on May 15, 2018, and hold office until their successors are duly elected and qualified. There are no family relationships between any directors or executive officers of Anadarko.

Item 1A. Risk Factors

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company has made in this Form 10-K, and may from time to time make in other public filings, press releases, and management discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include, among other things, information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," "would," "will," "potential," "continue," "forecast," "future," "likely," "outlook," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about energy markets*
- *production and sales volume levels*
- *levels of oil, natural-gas, and NGLs reserves*
- *operating results*
- *competitive conditions*
- *technology*
- *availability of capital resources, levels of capital expenditures, and other contractual obligations*
- *supply and demand for, the price of, and the commercialization and transporting of oil, natural gas, NGLs, and other products or services*
- *volatility in the commodity-futures market*
- *weather*
- *inflation*
- *availability of goods and services, including unexpected changes in costs*
- *drilling and other operational risks*
- *processing volumes, pipeline throughput, and produced water disposal*
- *general economic conditions, nationally, internationally, or in the jurisdictions in which the Company is, or in the future may be, doing business*
- *the Company's inability to timely obtain or maintain permits or other governmental approvals, including those necessary for drilling and/or development projects*
- *legislative or regulatory changes, including changes relating to hydraulic fracturing; retroactive royalty or production tax regimes; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation, including regulations related to climate change; environmental risks; and liability under international, provincial, federal, regional, state, tribal, local, and foreign environmental laws and regulations*

- *civil or political unrest or acts of terrorism in a region or country*
- *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties*
- *volatility in the securities, capital, or credit markets and related risks such as general credit, liquidity, and interest-rate risk*
- *the Company's ability to successfully monetize select assets, repay or refinance its debt, and the impact of changes in the Company's credit ratings*
- *the Company's ability to successfully complete its share-repurchase program*
- *uncertainties associated with acquired properties and businesses*
- *disruptions in international oil and NGLs cargo shipping activities*
- *physical, digital, cyber, internal, and external security breaches*
- *supply and demand, technological, political, governmental, and commercial conditions associated with long-term development and production projects in domestic and international locations*
- *the outcome of pending and future regulatory, legislative, or other proceedings or investigations, including the investigation by the NTSB related to the Company's operations in Colorado, and continued or additional disruptions in operations that may occur as the Company complies with regulatory orders or other state or local changes in laws or regulations in Colorado*
- *other factors discussed below and elsewhere in this Form 10-K, and in the Company's other public filings, press releases, and discussions with Company management*

RISK FACTORS

Our business and operations are subject to significant hazards and risks, such as the risks described below. Such risks may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. Each of these risks could adversely affect our business, financial condition and results of operations, as well as adversely affect the value of an investment in our common stock. The following risk factors should be read in conjunction with the other information contained herein, including the consolidated financial statements and the related notes.

Oil, natural-gas, and NGLs price volatility, including a substantial or extended decline in the price of these commodities, could adversely affect our financial condition and results of operations.

Prices for oil, natural gas, and NGLs can fluctuate widely. Our revenues, operating results, cash flows from operations, capital budget, and future growth rates are highly dependent on the prices we receive for our oil, natural gas, and NGLs. The markets for oil, natural gas, and NGLs have been volatile historically and may continue to be volatile in the future. Factors influencing the prices of oil, natural gas, and NGLs are beyond our control. These factors include, but are not limited to, the following:

- the domestic and worldwide supply of, and demand for, oil, natural gas, and NGLs
- volatility and trading patterns in the commodity-futures markets
- the cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs
- the level of global oil and natural-gas inventories
- weather conditions
- the level of U.S. exports of oil, LNG, or NGLs
- the ability of the members of OPEC and other producing nations to agree to and maintain production levels
- the worldwide military and political environment, civil and political unrest worldwide, including in Africa and the Middle East, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities, or acts of terrorism in the United States or elsewhere
- the effect of worldwide energy conservation and environmental protection efforts
- the price and availability of alternative and competing fuels
- the level of foreign imports of oil, natural gas, and NGLs
- domestic and foreign governmental laws, regulations, and taxes
- shareholder activism or activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development, and production of oil and natural gas
- the proximity to, and capacity of, natural-gas pipelines and other transportation facilities
- general economic conditions worldwide

The long-term effect of these and other factors on the prices of oil, natural gas, and NGLs is uncertain. Prolonged or substantial decline in these commodity prices may have the following effects on our business:

- adversely affect our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations
- reduce the amount of oil, natural gas, and NGLs that we can produce economically
- cause us to delay or postpone some of our capital projects
- reduce our revenues, operating income, or cash flows
- reduce the amounts of our estimated proved oil, natural-gas, and NGLs reserves
- reduce the carrying value of our oil, natural-gas, and midstream properties due to recognizing additional impairments of proved properties, unproved properties, exploration assets, and midstream facilities
- reduce the standardized measure of discounted future net cash flows relating to oil, natural-gas, and NGLs reserves
- limit our access to, or increasing the cost of, sources of capital such as equity and long-term debt
- adversely affect the ability of our partners to fund their working interest capital requirements

We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner, and feasibility of doing business.

Our operations and properties are subject to numerous international, provincial, federal, regional, state, tribal, local, and foreign laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- issuance of permits in connection with exploration, drilling, production, produced water disposal, and other midstream activities
- drilling activities on certain lands lying within wilderness, wetlands, and other protected areas
- types, quantities, and concentrations of emissions, discharges, and authorized releases
- generation, management, and disposition of waste materials
- offshore oil and natural-gas operations and decommissioning of abandoned facilities
- reclamation and abandonment of wells and facility sites
- remediation of contaminated sites
- protection of endangered species

These laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations, including the assessment of administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Moreover, changes in, or reinterpretations of, environmental laws and regulations governing areas where we operate may negatively impact our operations. Examples of recent proposed and final regulations or other regulatory initiatives include the following:

- *Ground-Level Ozone Standards.* In October 2015, the EPA issued a rule under the Clean Air Act, lowering the National Ambient Air Quality Standard for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The EPA did not meet the October 1, 2017 deadline for designating non-attainment areas but, on November 6, 2017, issued final designations for areas in the United States that are in attainment with the 70 parts per billion standard, representing approximately 85% of the U.S. counties that became effective on January 18, 2018. For the remaining areas of the United States, the EPA has not yet prepared final designations, but is expected to do so in a separate future action in the first half of 2018. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified facilities in new designated non-attainment areas. Also, states that are designated as non-attainment are expected to implement more stringent regulations, which could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.
- *Reduction of Methane Emissions by the Oil and Gas Industry.* In June 2016, the EPA published a final rule establishing new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified, and reconstructed oil and natural-gas production and natural-gas processing and transmission facilities. The EPA's rule is under the New Source Performance Standards, Subpart OOOOa, that requires certain new, modified, or reconstructed facilities in the oil and natural-gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards would expand previously issued New Source Performance Standards, Subpart OOOO, published by the EPA in 2012 by using certain equipment-specific emissions control practices with respect to, among other things, hydraulically fractured oil and natural-gas well completions, fugitive emissions from well sites and compressors, and pneumatic pumps. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards but the EPA has not yet published a final rule and, as a result, the June 2016 standards remain in effect, but future implementation of the standards are uncertain at this time. Furthermore, in June 2017, the Bureau of Land Management (BLM) stayed a rule published in November 2016 imposing requirements to reduce methane emissions from venting, flaring, and leaking on public lands. On October 4, 2017, the U.S. District Court for the Northern District of California struck down the June 2017 stay. However, on December 8, 2017, the BLM published a final rule that will temporarily suspend certain requirements contained in the November 2016 final rule until January 17, 2019. The December 2017 compliance extension was challenged by non-governmental organizations and several states on December 19, 2017. Notwithstanding the current uncertainty, we have taken measures to enter into a voluntary regime, together with certain other oil and natural gas exploration and production operators, to reduce methane emissions. At the state level, some states are considering and others have issued requirements, including Colorado where we conduct operations, for the performance of leak-detection programs that identify and repair methane leaks at certain oil and natural-gas sources. Compliance with these rules or future methane regulations will, among other things, require installation of new emission controls on some of our equipment and increase our capital expenditures and operating costs.

- *Induced Seismic Activity Associated with Oilfield Disposal Wells.* We dispose of wastewater generated from oil and natural-gas production operations directly or through the use of third parties. The legal requirements related to the disposal of wastewater in underground injections wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern relates to recent seismic events near injection wells used for the disposal of produced water resulting from oil and natural-gas activities. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Colorado developed and follows guidance when issuing underground injection control permits to limit the maximum injection pressure, rate, and volume of water. Oklahoma has issued rules for wastewater disposal wells that imposed certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults and also, from time to time, is developing and implementing plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. The Texas Railroad Commission has also adopted similar permitting, operating, and reporting rules for disposal wells. In addition, ongoing class action lawsuits, to which we are not currently a party, allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or by commercial disposal well vendors whom we may use from time to time to dispose of wastewater, which could have a material adverse effect on our capital expenditures and operating costs, financial condition, and results of operations.
- *Reduction of Greenhouse Gas Emissions.* The U.S. Congress and the EPA, in addition to some state and regional authorities, have in recent years considered legislation or regulations to reduce emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In the absence of federal GHG-limiting legislation, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the Clean Air Act and may require the installation of "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs together with other criteria pollutants. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified onshore and offshore production sources. In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. Although this international agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. In August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Climate Agreement, which would result in an effective exit date of November 2020. Notwithstanding any withdrawal from this agreement, the implementation of substantial limitations on GHG emissions in areas where we conduct operations could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves.

These and other regulatory changes could significantly increase our capital expenditures and operating costs or could result in delays to or limitations on our exploration and production activities, which could have an adverse effect on our financial condition, results of operations, or cash flows. For a description of certain environmental proceedings in which we are involved, see *Legal Proceedings* under Item 3 and *Note 17—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Laws and regulations regarding hydraulic fracturing or other oil and natural-gas operations could increase our costs of doing business, result in additional operating restrictions or delays, limit the areas in which we can operate, and adversely affect our production.

Hydraulic fracturing is an essential and common practice used to stimulate production of oil and natural gas from dense subsurface rock formations such as shales. We routinely apply hydraulic-fracturing techniques in many of our U.S. onshore oil and natural-gas drilling and completion programs. The process involves the injection of water, sand or alternative proppant, and chemical additives under pressure into a targeted subsurface formation to fracture the surrounding rock and stimulate production.

Hydraulic fracturing is typically regulated by state oil and natural-gas commissions and similar agencies. However, several federal agencies have also asserted regulatory authority over certain aspects of the process. For example, in June 2016, the EPA published a final rule prohibiting the discharge of return water recovered from shale natural-gas extraction operations to publicly owned wastewater treatment plants. Also, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian land. This rule was struck down by a Wyoming federal judge, but in June 2016, the decision was appealed by the BLM to the U.S. Circuit Court of Appeals for the Tenth Circuit. However, in July 2017, the BLM published a proposed rule to rescind the 2015 final rule. In September 2017, the Tenth Circuit Court issued a ruling to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in light of the BLM's proposed rulemaking. The timing of a final rulemaking to rescind the 2015 rule is uncertain and, as a result of these developments, future implementation of the 2015 rule is uncertain at this time. Also, from time to time, legislation has been introduced, but not enacted, in the U.S. Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In the event that new federal restrictions on the hydraulic-fracturing process are adopted in areas where we operate, we may incur significant additional costs or permitting requirements to comply with such federal requirements, and could experience added delays or curtailment in the pursuit of exploration, development, or production activities.

In addition to asserting regulatory authority, a number of federal entities have reviewed various environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances".

Certain states in which we operate, including Colorado, Pennsylvania, Louisiana, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, or other regulatory requirements on hydraulic-fracturing or other oil and natural-gas operations, including subsurface water disposal. For instance, in May 2017, the Colorado Oil & Gas Conservation Commission (COGCC) issued a two-phase Notice to Operators (NTO) requiring all operators to inventory and integrity test existing flowlines within 1,000 feet of a building unit and inspect and complete abandonment of all inactive flowlines regardless of distance to a building unit. Furthermore, in August 2017, following a three month review of oil and gas operations, the Governor of Colorado announced several policy initiatives designed to enhance public safety, which are to be implemented through rulemaking or legislation. As part of these policy initiatives, on February 13, 2017, the COGCC approved new regulations addressing the operation of flowlines and related infrastructure associated with oil and natural-gas development, including more stringent requirements relating to design, installation, maintenance, testing, tracking, and abandoning of flowlines.

States also could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York. In addition to state laws, local land use restrictions, such as city ordinances, may restrict drilling in general and/or hydraulic fracturing in particular. For example, several cities in Colorado passed temporary or permanent moratoria on hydraulic fracturing within their respective city limits beginning in 2012 but, since that time, local district courts have struck down the ordinances for certain of those Colorado cities, which decisions were upheld by the Colorado Supreme Court in 2016. Notwithstanding attempts at the local level to prohibit hydraulic fracturing, the opportunity exists for cities to adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions while regulating the time, place, and manner of those activities.

Additionally, certain interest groups in Colorado opposed to oil and natural-gas development generally, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives that, if approved, would allow revisions to the state constitution in a manner that would make such exploration and production activities in the state more difficult or expensive in the future. However, an amendment on the Colorado 2016 ballot was approved by voters, making it more difficult to place an initiative to amend the constitution on the state ballot by requiring signatures from 2% of registered voters from each of the state's 35 Senate districts and approval by 55% of the voters. In the event that ballot initiatives, local or state restrictions, or prohibitions are adopted and result in more stringent limitations on the production and development of oil and natural gas in areas where we conduct operations, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the permitting or pursuit of exploration, development, or production activities. In addition, we could possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Such compliance costs and delays, curtailments, limitations, or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

Our Tronox settlement may not be deductible for income tax purposes, and we may be required to repay the tax refund of $881 million received in 2016 related to the deduction of the Tronox settlement payment, which may have a material adverse effect on our results of operations, liquidity, and financial condition.

In April 2014, Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) entered into a settlement agreement for $5.15 billion, resolving all claims that were or could have been asserted in the Tronox Adversary Proceeding. After the settlement became effective in January 2015, we paid $5.2 billion and deducted this payment on our 2015 federal income tax return. Due to the deduction, we had a net operating loss carryback for 2015, which resulted in a tentative tax refund of $881 million in 2016. In our financial statements, we have recorded an uncertain tax position greater than the amount of the tentative tax refund received.

The IRS has audited our tax position regarding the deductibility of the payment and issued a draft notice of proposed adjustment denying our deduction in its entirety. We disagree and plan to defend our tax position. It is possible that we may not ultimately succeed in defending this deduction. We could be required to repay all or a portion of the tentative refund received, with interest, prior to determining the final outcome of our tax position either upon IRS request or litigation of the matter in District or Federal Claims Court. If the payment is ultimately determined not to be deductible, we would be required to repay the tentative refund received plus interest and reverse the net benefit of $346 million previously recognized in our consolidated financial statements, which could have a material adverse effect on our results of operations, liquidity, and financial condition. For additional information on income taxes, see *Note 13—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Our debt and other financial commitments may limit our financial and operating flexibility.

At December 31, 2017, our total debt of $15.7 billion consisted of $12.2 billion related to Anadarko and $3.5 billion related to WES and WGP. We also have various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services and products. Our financial commitments could have important consequences to our business, including, but not limited to, the following:

- increasing our vulnerability to general adverse economic and industry conditions
- limiting our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flows from operations to payments on our debt or to comply with any restrictive terms of our debt
- limiting our flexibility in planning for, or reacting to, changes in the industry in which we operate
- placing us at a competitive disadvantage compared to our competitors that have less debt and/or fewer financial commitments

Additionally, the credit agreements governing the APC RCF and our 364-Day Facility contain a number of customary covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% (excluding the effect of non-cash write-downs), and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. Our ability to meet such covenants may be affected by events beyond our control.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

As of December 31, 2017, our long-term debt was rated “BBB” with a stable outlook by S&P and Fitch. Our long-term debt was rated “Ba1” with a stable outlook by Moody’s, which is below investment grade. As of the time of filing this Form 10-K, no additional changes in our credit rating have occurred and we are not aware of any current plans of S&P, Fitch, or Moody’s to revise their respective credit ratings on our long-term debt; however, we cannot be assured that our credit ratings will not be further downgraded. Any further downgrade in our credit ratings could negatively impact our cost of capital and could also adversely affect our ability to effectively execute aspects of our strategy or to raise debt in the public debt markets.

As a result of Moody’s below-investment-grade rating of our long-term debt in February 2016, we are more likely to be required to post collateral in the form of letters of credit or cash as financial assurance of our performance under certain contractual arrangements such as pipeline transportation contracts and oil and gas sales contracts. The amount of letters of credit or cash provided as assurance of our performance under these types of contractual arrangements with respect to credit-risk-related contingent features was $263 million at December 31, 2017, and $274 million at December 31, 2016. Additionally, certain of these arrangements contain financial-assurances language that may, under certain circumstances, permit our counterparties to request additional collateral.

Furthermore, as a result of Moody’s rating, the credit thresholds with certain derivative counterparties were reduced and in some cases eliminated, which required us to increase the amount of collateral posted with derivative counterparties when our net trading position is a liability in excess of the contractual threshold. We may be required to post additional collateral with respect to our derivative instruments if our credit ratings decline below current levels. For example, based on year-end derivative positions, if Anadarko’s credit rating were to be downgraded one level by either S&P or Moody’s, we would be required to post additional collateral of up to approximately $50 million. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.4 billion (net of $170 million of collateral) at December 31, 2017, and $1.4 billion (net of $117 million of collateral) at December 31, 2016. For additional information, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Additionally, in February 2016, Moody’s downgraded our commercial paper program credit rating, which eliminated our access to the commercial paper market.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control that could cause the quantities and net present value of our reserves to be overstated or understated. The reserves information included or incorporated by reference in this Form 10-K represents estimates prepared by our internal engineers. The procedures and methods for estimating the reserves by our internal engineers were reviewed by independent petroleum consultants; however, no reserves audit was conducted by these consultants. Estimation of reserves is not an exact science. Estimates of economically recoverable oil, natural-gas, and NGLs reserves and of future net cash flows depend on a number of variable factors and assumptions, any of which may cause actual results to vary considerably from these estimates. These factors and assumptions may include, but are not limited to, the following:

- estimated future production from an area is consistent with historical production from similar producing areas
- assumed effects of regulation by governmental agencies and court rulings
- assumptions concerning future oil, natural-gas, and NGLs prices, future operating costs, and capital expenditures
- estimates of future severance and excise taxes, workover costs, and remedial costs

Estimates of reserves based on risk of recovery and estimates of expected future net cash flows prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and the variance may be material. The discounted cash flows included in this Form 10-K should not be construed as the fair value of the estimated oil, natural-gas, and NGLs reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the average beginning-of-month prices during the 12-month period for the respective year. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating future discounted net cash flows from proved reserves. Therefore, reserves quantities will change when actual prices increase or decrease.

Failure to replace reserves may negatively affect our business.

Our future success depends on our ability to find, develop, or acquire additional oil and natural-gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities, acquire properties containing proved reserves, or both. We may be unable to find, develop, or acquire additional reserves on an economic basis. Furthermore, if oil and natural-gas prices increase, our costs for finding or acquiring additional reserves could also increase.

Our domestic operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex provincial, federal, regional, state, tribal, local, and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies, price or gathering-rate controls, and hydraulic fracturing, induced seismicity, and environmental protection regulations. To the extent our domestic operations are offshore, we must also comply with requirements focused on oil and natural-gas exploration and production activities in coastal and outer continental shelf (OCS) waters. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various provincial, federal, regional, state, tribal, and local governmental authorities. We may incur substantial costs to maintain compliance with these existing laws and regulations.

Future economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, potential default on U.S. debt, energy costs, geopolitical issues, the availability and cost of credit, and uncertainties with regard to European sovereign debt, have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. Continued concerns could cause demand for petroleum products to diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs and impede the execution of long-term sales agreements or prices thereunder, which are the basis for future LNG production; affect the ability of our vendors, suppliers, and customers to continue operations; and ultimately adversely impact our results of operations, liquidity, and financial condition.

We are vulnerable to risks associated with our offshore operations that could negatively impact our operations and financial results.

We conduct offshore operations in the Gulf of Mexico, Ghana, Mozambique, and other countries. Our operations and financial results could be significantly impacted by conditions in some of these areas and are also vulnerable to certain unique risks associated with operating offshore, including those relating to the following:

- hurricanes and other adverse weather conditions
- geological complexities and water depths associated with such operations
- limited number of partners available to participate in projects
- oilfield service costs and availability
- compliance with environmental, safety, and other laws and regulations
- terrorist attacks or piracy
- remediation and other costs and regulatory changes resulting from oil spills or releases of hazardous materials
- failure of equipment or facilities
- response capabilities for personnel, equipment, or environmental incidents

In addition, we conduct some of our exploration in deep waters (greater than 1,000 feet) where operations, support services, and decommissioning activities are more difficult and costly than in shallower waters. The deep waters in the Gulf of Mexico, as well as international deepwater locations, lack the physical and oilfield service infrastructure present in shallower waters. As a result, deepwater operations may require significant time between a discovery and the time that we can market our production, thereby increasing the risk involved with these operations.

Additional domestic and international deepwater drilling laws, regulations, and other restrictions; delays in the processing and approval of drilling permits and exploration, development, oil spill-response, and decommissioning plans; and other related developments may have a material adverse effect on our business, financial condition, or results of operations.

In recent years, the Bureau of Ocean Energy Management (BOEM) and the BSEE, agencies of the U.S. Department of the Interior, have imposed more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. For example, in 2016, BSEE finalized rule-making entitled "Oil and Sulfur Operations on the Outer Continental Shelf — Blowout Prevention Systems and Well Control," which focuses on well blowout preventer systems and well control with respect to operations on the OCS. Compliance with these more stringent regulatory requirements and with existing environmental and oil spill regulations, together with any uncertainties or inconsistencies in decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts.

In addition, new regulatory initiatives may be adopted or enforced by the BOEM or the BSEE in the future that could result in additional costs, delays, restrictions, or obligations with respect to oil and natural-gas exploration and production operations conducted offshore. For example, in April 2016, the BOEM published a proposed rule that would update existing air-emissions requirements relating to offshore oil and natural-gas activity on federal OCS waters including in the Central Gulf of Mexico. In addition, in September 2016, the BOEM issued a Notice to Lessees and Operators that would bolster supplemental bonding procedures for the decommissioning of offshore wells, platforms, pipelines, and other facilities; however, since the BOEM's issuance of the Notice to Lessees, the agency has delayed the implementation timeline for most of those facilities so that BOEM could further assess this financial assurance program, but this delay is expected to be temporary. These regulatory actions, or any new rules, regulations, or legal initiatives, could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases. Moreover, under existing BOEM and BSEE rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interests may be held jointly and severally liable for decommissioning of OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BSEE to decommission OCS facilities that one of our assignees of offshore facilities is unwilling or unable to perform, we could incur costs to perform those decommissioning obligations, which costs could be material.

In addition, our offshore development activities rely on subcontractors to perform certain offshore construction and installation activities. The Jones Act requires that vessels engaged in U.S. coastwise trade be built in the United States, registered under the U.S. flag, manned by predominantly U.S. crews, and owned and operated by U.S. citizens within the meaning of the Jones Act. Under existing U.S. Customs & Border Protection (CBP) rulings, the Jones Act is not applicable to foreign vessels conducting certain construction and pipeline installation activities on the OCS. Recently, the U.S. Marine Vessel Owners Association filed a lawsuit seeking to compel CBP to revoke a number of long-standing ruling letters relating to this exemption. The outcome of this litigation is uncertain. However, if the litigation is successful and the rulings are revoked, foreign flagged vessels could no longer perform certain operations for us in compliance with the Jones Act. The existing fleet of U.S. vessels are currently incapable of performing these construction and installation activities. As a result, certain of our development efforts could be delayed, disrupted or even suspended.

Also, if material spill events were to occur in the future, the United States or other countries where such an event were to occur could issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development. We cannot predict with any certainty the full impact of any new laws, regulations, or legal initiatives on our drilling operations or on the cost or availability of insurance to cover the risks associated with such operations. The overall costs to implement and complete any such spill response activities or any decommissioning obligations could exceed estimated accruals, insurance limits, or supplemental bonding amounts, which could result in the incurrence of additional costs to complete.

Further, the deepwater Gulf of Mexico (as well as international deepwater locations) lacks the degree of physical and oilfield service infrastructure present in shallower waters. Therefore, despite our oil spill-response capabilities, it may be difficult for us to quickly or effectively execute any contingency plans related to potential material events in the future.

The matters described above, individually or in the aggregate, could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

We operate in foreign countries and are subject to political, economic, and other uncertainties.

We have operations outside the United States, including in Algeria, Ghana, Mozambique, Colombia, and other countries. As a result, we face political and economic risks and other uncertainties with respect to our international operations. These risks may include the following, among other things:

- loss of revenue, property, and equipment or delays in operations as a result of hazards such as expropriation, war, piracy, acts of terrorism, insurrection, civil unrest, and other political risks, including tension and confrontations among political parties
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act, the U.K. Bribery Act, and other anti-corruption compliance laws and issues
- increases in taxes and governmental royalties
- unilateral renegotiation of contracts by governmental entities
- redefinition of international boundaries or boundary disputes
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations
- changes in laws and policies governing operations of foreign-based companies
- foreign-exchange restrictions
- international monetary fluctuations and changes in the relative value of the U.S. dollar as compared to the currencies of other countries in which we conduct business

Outbreaks of civil and political unrest and acts of terrorism have occurred in countries in Europe, Africa, South America, and the Middle East, including countries close to or where we conduct operations. Continued or escalated civil and political unrest and acts of terrorism in the countries in which we operate could result in our curtailing operations. In the event that countries in which we operate experience civil or political unrest or acts of terrorism, especially in events where such unrest leads to an unseating of the established government, our operations in such countries could be materially impaired.

Our international operations may also be adversely affected, directly or indirectly, by laws, policies, and regulations of the United States affecting foreign trade and taxation, including U.S. trade sanctions.

Realization of any of the factors listed above could materially and adversely affect our financial condition, results of operations, or cash flows.

The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, or qualified personnel. The cost for such items may increase as a result of a variety of factors beyond our control, such as increases in the cost of electricity, steel, and other raw materials that we and our vendors rely upon; increased demand for labor, services, and materials as drilling activity increases; and increased taxes. Decreased levels of drilling activity in the oil and gas industry in recent periods have led to declining costs of some drilling rigs, equipment, supplies, or qualified personnel. However, if commodity prices rise, such costs may rise faster than increases in our revenue and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Deterioration in the credit or equity markets could adversely affect us.

We have exposure to different counterparties. For example, we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds, and other institutions. These transactions expose us to credit risk in the event of default by our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions through our derivative transactions. In addition, if any lender under our credit facilities is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender’s commitment under our credit facilities. Moreover, to the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to us if such purchasers were unable to access the credit or equity markets for an extended period of time.

Exploration, development, and production activities carry inherent risk. These activities could result in liability exposure or the loss of production and revenues. In addition, we are not insured against all of the operating risks to which our business is exposed.

Our business is subject to all of the hazards and operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and natural gas, including blowouts; cratering and fire; environmental hazards such as natural-gas leaks, oil spills, pipeline and vessel ruptures, and releases of chemicals or other hazardous substances, any of which could result in damage to, or destruction of, oil and natural-gas wells or formations, production facilities, and other property; pollution or other environmental damage; and injury to persons. Some of these risks or hazards could materially and adversely affect our revenues and expenses by reducing or shutting in production from wells, resulting in loss of equipment or otherwise negatively impacting the projected economic performance of our projects. Any of these risks or hazards can result in injuries and/or deaths of employees, supplier personnel or other individuals, loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others, regulatory investigations, litigation, fines, and penalties or restricted access to our properties.

For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/loss of control of a well, comprehensive general liability, aviation liability, and worker’s compensation and employer’s liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing and for certain risks, such as political risk, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial condition, results of operations, or cash flows.

Our commodity-price risk-management and trading activities may prevent us from fully benefiting from price increases and may expose us to regulatory and other risks.

To the extent that we engage in commodity-price risk-management activities to protect our cash flows from commodity-price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which the following occur:

- our production is less than the notional volumes
- a widening of price basis differentials occurs between delivery points for our production and the delivery point assumed in the derivative arrangement
- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements
- a sudden unexpected event materially impacts oil, natural-gas, or NGLs prices

We are required to observe the market-related regulations enforced by the Commodity Futures Trading Commission and other agencies with regard to our commodity-price risk-management activities, which hold substantial enforcement authority. Failures to comply with such regulations, as interpreted and enforced, could materially and adversely affect our results of operations and financial condition.

Material differences between the estimated and actual timing of critical events may affect the completion of and commencement of production from development projects.

We are involved in several large development projects and the completion of those projects may be delayed beyond our anticipated completion dates. Key factors that may affect the timing and outcome of such projects include the following:

- project approvals and funding by joint-venture partners
- timely issuance of permits and licenses by governmental agencies or legislative and other governmental approvals
- weather conditions
- availability of qualified personnel
- civil and political environment of, and existing infrastructure in, the country or region in which the project is located
- manufacturing and delivery schedules of critical equipment
- commercial arrangements for pipelines, tankers, and related equipment to transport and market hydrocarbons

Delays and differences between estimated and actual timing of critical events may affect the forward-looking statements related to large development projects and could have a material adverse effect on our results of operations.

The oil and gas exploration and production industry is very competitive, and some of our exploration and production competitors have greater financial and other resources than we do.

The oil and gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production. Our competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies as well as participants in other industries supplying energy and fuel to consumers. Some of our competitors may have greater and more diverse resources on which to draw than we do. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

Our drilling activities may not encounter commercially productive oil or natural-gas reservoirs.

Drilling for oil and natural gas involves numerous risks, including the risk that we will not encounter commercially productive oil or natural-gas reservoirs. Drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including the following:

- unexpected drilling conditions
- pressure or irregularities in formations
- equipment failures or accidents
- fires, explosions, blowouts, and surface cratering
- marine risks such as capsizing, collisions, and hurricanes
- difficulty identifying and retaining qualified personnel
- title problems
- other adverse weather conditions
- lack of availability or delays in the delivery of technology, equipment, or resources for operations

Certain of our future drilling activities may not be successful and, if unsuccessful, could result in a material adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because a portion of our capital budget is devoted to higher-risk exploratory projects, it is likely that we will continue to experience significant exploration and dry hole expenses.

We have limited influence over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence the operation or future development of these nonoperated properties or the amount or timing of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working-interest owners for these projects and our limited ability to influence the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital, lead to unexpected future costs, or adversely affect the timing of activities.

Our ability to sell and deliver our oil, natural-gas, and NGLs production could be materially harmed if adequate gathering, processing, compression, transportation, and disposal facilities and equipment are unavailable.

The marketability of our production depends in part on the availability, proximity, and capacity of gathering, processing, compression, transportation, tankers, pipeline, and produced water facilities. These facilities may be temporarily unavailable to us due to market conditions, regulatory reasons, mechanical reasons or other factors or conditions. If any pipelines or tankers become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport the oil, natural gas, and NGLs, which could increase our costs and/or reduce the revenues we might obtain from the sale of the oil and natural-gas. In addition, in certain newer plays, the capacity of gathering, processing, compression, transportation, and disposal facilities and equipment may not be sufficient to accommodate potential production from existing and new wells. Construction and permitting delays, permitting costs and regulatory or other constraints could limit or delay the construction, manufacture or other acquisition of new gathering, processing, compression, transportation, and disposal facilities and equipment, and we may experience delays or increased costs in accessing the pipelines, gathering systems or rail systems necessary to transport our production to points of sale or delivery or disposing of produced water.

Any significant change in market or other conditions affecting gathering, processing, compression, transportation, or disposal facilities and equipment or the availability of these facilities, including due to our failure or inability to obtain access to these facilities and equipment on terms acceptable to us or at all, could materially and adversely affect our business and, in turn, our financial condition and results of operations.

Our results of operations could be adversely affected by goodwill impairments.

As a result of mergers and acquisitions, we had approximately $4.8 billion of goodwill on our Consolidated Balance Sheet at December 31, 2017. Goodwill must be tested at least annually for impairment, and more frequently when circumstances indicate likely impairment. Goodwill is considered impaired to the extent that its carrying amount exceeds its implied fair value. Various factors could reduce the fair value of a reporting unit such as our inability to replace the value of our depleting asset base, difficulty or potential delays in obtaining drilling permits, or other adverse events such as lower oil and natural-gas prices, which could lead to an impairment of goodwill. An impairment of goodwill could have a substantial negative effect on our reported earnings.

Risks related to acquisitions may adversely affect our business, financial condition, and results of operations.

Any acquisition, including the GOM Acquisition, involves potential risks, including, among other things:

- the validity of our assumptions about, among other things, reserves, estimated production, revenues, capital expenditures, operating expenses, and costs
- the assumption of environmental, decommissioning, and other liabilities, and losses or costs for which we are not indemnified or for which our indemnity is inadequate
- a failure to attain or maintain compliance with environmental, safety, and other governmental regulations

If any of these risks materialize, the benefits of such acquisition may not be fully realized, if at all, and our business, financial condition, and results of operations could be negatively impacted.

Our business could be negatively affected by security threats, including cyber threats, and other disruptions.

As an oil and gas producer, we face various security threats, including cyber threats such as attempts to gain unauthorized access to, or control of, sensitive information or to render data or systems corrupted or unusable; threats to the security of our facilities and infrastructure or those of third parties such as processing plants and pipelines; and threats from terrorist acts. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure may result in increased costs. We continuously work to install new, and upgrade existing, information technology systems and provide employee awareness training on phishing, malware, and other cyber risks to help ensure that we are protected, to the extent possible, against cyber risks and security breaches. We also perform periodic drills for responding to cyber incidences. There can be no assurance that such safeguards, procedures, and controls will be sufficient to prevent security breaches from occurring. Cyber attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to, or control of our data, systems, or facilities, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data or systems, which could have an adverse effect on our reputation, financial condition, results of operations, or cash flows.

While we have experienced cyber attacks, we have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. In addition, as cyber threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cyber vulnerabilities.

Provisions in our corporate documents and Delaware law could delay or prevent a change of control of Anadarko, even if that change would be beneficial to our stockholders.

Our restated certificate of incorporation and by-laws contain provisions that may make a change of control of Anadarko difficult, even if it may be beneficial to our stockholders, including provisions governing the nomination and removal of directors, the prohibition of stockholder action by written consent and regulation of stockholders' ability to bring matters for action before annual stockholder meetings, and the authorization given to our Board of Directors to issue and set the terms of preferred stock.

In addition, Section 203 of the Delaware General Corporation Law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

We may reduce or cease to pay dividends on our common stock.

We can provide no assurance that we will continue to pay dividends at the current rate or at all. As of February 2018, our quarterly dividend was $0.25 per share. The amount of cash dividends, if any, to be paid in the future is determined by our Board of Directors based on our financial condition, results of operations, cash flows, levels of capital and exploration expenditures, future business prospects, expected liquidity needs, and other matters that our Board of Directors deems relevant.

Difficulty attracting and retaining experienced technical personnel could reduce our competitiveness and prospects for future success.

Our exploratory drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers, and other professionals. Competition for such professionals could be intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including personal injury and death claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, development, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, tribal, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

WGR Operating, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the EPA with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Granger, Wyoming facilities. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

Anadarko E&P Onshore LLC, a wholly owned subsidiary of the Company, is currently in negotiations with the Pennsylvania Department of Environmental Protection concerning enforcement over a produced water release in Pennsylvania in 2015. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of these matters will result in a fine or penalty in excess of $100,000.

Kerr-McGee Oil and Gas Onshore, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the State of Colorado's Department of Public Health and Environment with respect to alleged noncompliance with the Colorado Air Quality Control Commission's Regulations. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

Kerr-McGee Gathering, LLC, a wholly owned subsidiary of the Company, is currently in negotiations with the EPA and the Department of Justice with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Fort Lupton complex. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

In December 2017, the Company entered into a consent agreement and final order with the EPA with respect to alleged violations of the U.S. Resource Conservation and Recovery Act at certain facilities associated with the Gulf of Mexico and agreed to pay a penalty of approximately $1.4 million. There were no allegations that waste was improperly disposed of or released into the environment.

Delaware Basin Midstream, LLC, a subsidiary of the Company, is currently in negotiations with the EPA with respect to alleged noncompliance with certain Risk Management Plan regulations under the Clean Air Act at its Ramsey Gas Plant. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

See *Note 17—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, which is incorporated herein by reference, for a discussion of material legal proceedings to which the Company is a party.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

MARKET INFORMATION, HOLDERS, AND DIVIDENDS

At January 31, 2018, there were approximately 9,680 holders of record of Anadarko common stock. The common stock of Anadarko is traded on the New York Stock Exchange. The following shows information regarding the market price of, and dividends declared and paid on, the Company's common stock by quarter for 2017 and 2016:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Market Price				
High	**$ 72.32**	**$ 64.15**	**$ 50.16**	**$ 54.45**
Low	**$ 59.34**	**$ 43.45**	**$ 39.96**	**$ 46.75**
Dividends	**$ 0.05**	**$ 0.05**	**$ 0.05**	**$ 0.05**
2016				
Market Price				
High	$ 50.39	$ 57.00	$ 63.84	$ 73.33
Low	$ 28.16	$ 43.52	$ 50.23	$ 58.59
Dividends	$ 0.05	$ 0.05	$ 0.05	$ 0.05

The amount of future common stock dividends will depend on the Company's earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors and will be determined by the Board of Directors on a quarterly basis. In February 2018, the Company announced an increase in the quarterly dividend to $0.25 per share of common stock. For additional information, see *Liquidity and Capital Resources—Financing Activities—Common Stock Dividends* and *Distributions to Noncontrolling Interest Owners* under Item 7 of this Form 10-K.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the Company at December 31, 2017:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	6,567,944	$ 71.44	27,094,327
Equity compensation plans not approved by security holders	—	—	—
Total	6,567,944	$ 71.44	27,094,327

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PERSONS

The following sets forth information with respect to repurchases made by the Company of its shares of common stock during the fourth quarter of 2017:

Period	Total number of shares purchased [1]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs [2]	Approximate dollar value of shares that may yet be purchased under the plans or programs [2]
October 1-31, 2017 [3]	15,698,241	$ 48.13	15,679,096	$ 1,745,327,838
November 1-30, 2017	44,950	$ 51.09	—	$ 1,745,327,838
December 1-31, 2017 [3]	6,239,532	$ 48.84	6,236,398	$ 1,440,745,052
Total	21,982,723	$ 48.34	21,915,494	

(1) During the fourth quarter of 2017, (i) 21.9 million shares were purchased under the $3.0 Billion Share-Repurchase Program and (ii) 67 thousand shares were purchased related to stock received by the Company for the payment of withholding taxes due on employee share issuances under share-based compensation plans. For additional information, see *Note 22—Share-Based Compensation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) At December 31, 2017, the Company had repurchased, through open-market and private transactions, approximately $1.1 billion of common stock under its share-repurchase program in place at year end, which was expanded by $500 million in February 2018 under the $3.0 Billion Share-Repurchase Program. In February 2018, the Company completed the repurchase of an additional 8.5 million shares as part of an ASR Agreement. For additional information, see *Note 20—Stockholders' Equity* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

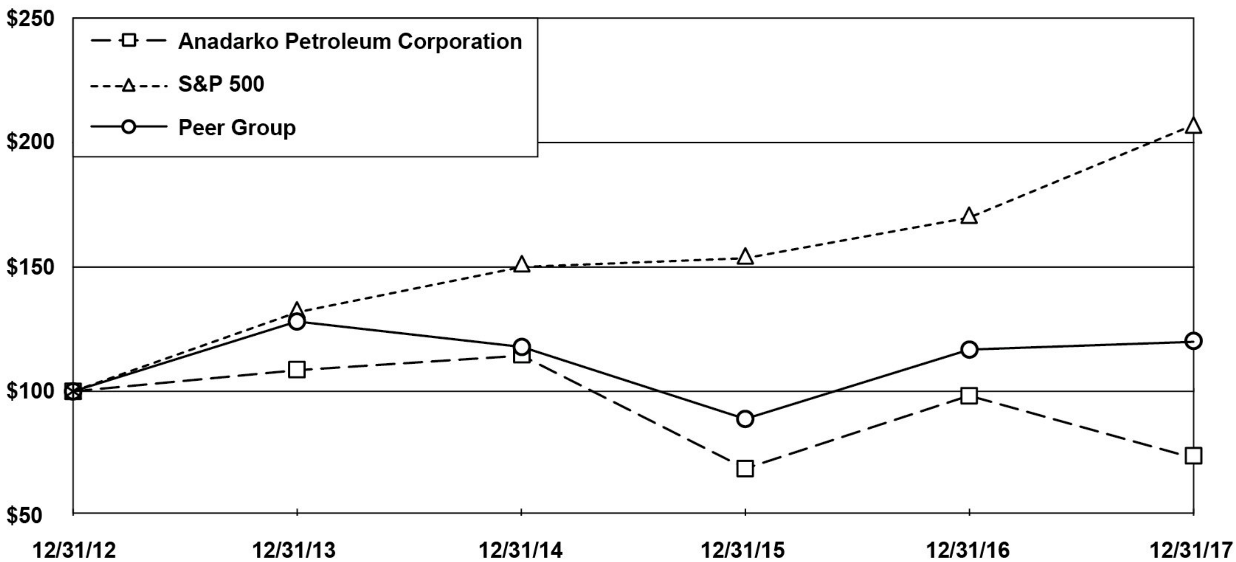
(3) In October 2017, the Company entered into an ASR Agreement to complete $1.0 billion of the $3.0 Billion Share-Repurchase Program and received an initial delivery of 15.7 million shares. The transaction was completed in December 2017, at which time the Company received an additional 5.1 million shares to settle the agreement. The settlement price was determined by the volume-weighted average price of the shares during the term less a negotiated settlement price adjustment. During the fourth quarter of 2017, the Company repurchased an additional 1.1 million shares for $59 million through open-market purchases. For additional information, see *Note 20—Stockholders' Equity* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

PERFORMANCE GRAPH

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall the information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following graph compares the cumulative five-year total return to stockholders of Anadarko's common stock relative to the cumulative total returns of the S&P 500 index and a peer group of 11 companies. The companies included in the peer group are Apache Corporation; Chesapeake Energy Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; and Pioneer Natural Resources Company.

Comparison of 5-Year Cumulative Total Return Among Anadarko Petroleum Corporation, the S&P 500 Index, and a Peer Group



An investment of $100 (with reinvestment of all dividends) is assumed to have been made in the Company's common stock, in the S&P 500 Index, and in the peer group on December 31, 2012, and its relative performance is tracked through December 31, 2017.

Fiscal Year Ended December 31	2012	2013	2014	2015	2016	**2017**
Anadarko Petroleum Corporation	$ 100.00	$ 107.39	$ 112.91	$ 67.53	$ 97.28	$ 75.14
S&P 500	100.00	132.39	150.51	152.59	170.84	208.14
Peer Group	100.00	126.49	116.48	88.51	115.49	119.42

Item 6. Selected Financial Data

	Summary Financial Information (1)				
millions except per-share amounts	**2017**	2016	2015	2014	2013
Sales Revenues	**$ 10,969**	$ 8,447	$ 9,486	$ 16,375	$ 14,867
Gains (Losses) on Divestitures and Other, net	**939**	(578)	(788)	2,095	(286)
Total Revenues and Other	**11,908**	7,869	8,698	18,470	14,581
Operating Income (Loss)	**(672)**	(2,599)	(8,809)	5,403	3,333
Tronox-related Contingent Loss	**—**	—	5	4,360	850
Net Income (Loss) (2)	**(211)**	(2,808)	(6,812)	(1,563)	941
Net Income (Loss) Attributable to Common Stockholders	**(456)**	(3,071)	(6,692)	(1,750)	801
Per Common Share (amounts attributable to common stockholders)					
Net Income (Loss)—Basic	**$ (0.85)**	$ (5.90)	$ (13.18)	$ (3.47)	$ 1.58
Net Income (Loss)—Diluted	**$ (0.85)**	$ (5.90)	$ (13.18)	$ (3.47)	$ 1.58
Dividends	**$ 0.20**	$ 0.20	$ 1.08	$ 0.99	$ 0.54
Average Number of Common Shares Outstanding—Basic	**548**	522	508	506	502
Average Number of Common Shares Outstanding—Diluted	**548**	522	508	506	505
Cash Provided by (Used in) Operating Activities (3)	**4,009**	3,000	(1,877)	8,466	8,888
Capital Expenditures	**$ 5,300**	$ 3,314	$ 5,888	$ 9,256	$ 8,523
Short-term Debt - Anadarko (4)	**$ 142**	$ 42	$ 32	$ —	$ 500
Long-term Debt - Anadarko (4)	**12,054**	12,162	12,945	12,595	11,576
Long-term Debt - WES and WGP	**3,493**	3,119	2,691	2,409	1,408
Total Debt	**$ 15,689**	$ 15,323	$ 15,668	$ 15,004	$ 13,484
Total Stockholders' Equity	**10,696**	12,212	12,819	19,725	21,857
Total Assets	**$ 42,086**	$ 45,564	$ 46,331	$ 60,879	$ 55,340
Annual Sales Volumes					
Oil (MMBbls)	**129**	116	116	106	91
Natural Gas (Bcf)	**478**	766	852	945	968
Natural Gas Liquids (MMBbls)	**36**	46	47	44	33
Total (MMBOE) (5)	**245**	290	305	308	285
Average Daily Sales Volumes					
Oil (MBbls/d)	**355**	316	317	292	248
Natural Gas (MMcf/d)	**1,309**	2,093	2,334	2,589	2,652
Natural Gas Liquids (MBbls/d)	**99**	128	130	119	91
Total (MBOE/d)	**672**	793	836	843	781
Proved Reserves					
Oil Reserves (MMBbls)	**658**	702	713	929	851
Natural-gas Reserves (Tcf)	**3.2**	4.4	6.0	8.7	9.2
Natural-gas Liquids Reserves (MMBbls)	**243**	283	340	479	407
Total Proved Reserves (MMBOE)	**1,439**	1,722	2,057	2,858	2,792
Number of Employees	**4,400**	4,500	5,800	6,100	5,700

(1) Consolidated for Anadarko and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.

(2) Includes one-time deferred tax benefit of $1.2 billion in 2017 related to Tax Reform Legislation.

(3) Includes Tronox settlement payment of $5.2 billion in 2015.

(4) Excludes WES and WGP.

(5) Natural gas is converted to equivalent barrels at the rate of 6,000 cubic feet of gas per barrel.

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

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-K in Item 8, and the information set forth in *Risk Factors* under Item 1A.

MANAGEMENT OVERVIEW

Anadarko's strategy is to explore for, develop, and commercialize resources globally; ensure health, safety, and environmental excellence; focus on financial discipline, flexibility, and value creation; and demonstrate the Company's core values in all its business activities. The Company's revenues, operating results, cash flows from operations, capital spending, and future growth rates are highly dependent on commodity prices, which affect the value the Company receives from its sales of oil, natural gas, and NGLs.

Over the last several years, Anadarko has actively managed its portfolio to focus on higher-return, oil-levered opportunities, namely in the Delaware and DJ basins in the U.S. onshore and the deepwater Gulf of Mexico. Anadarko has divested non-core gas-focused assets while also completing the GOM Acquisition in late 2016, which doubled the Company's production in the Gulf of Mexico and strengthened its infrastructure and tie-back inventory. As a result of this portfolio transformation, the Company's overall sales-volume product mix increased to 53% oil in 2017, compared to 40% in 2016, which significantly improved margins and returns.

2018 Outlook The Company's 2018 capital program is designed to enhance shareholder value by delivering an attractive cash return on invested capital in a $50 oil (for both WTI and Brent) and $3 natural gas (Henry Hub) price environment while advancing the development of the Company's core assets. If realized commodity prices are above investment assumptions, Anadarko plans to focus on returning value directly to the stockholders versus material increases to activity, capital expenditures, and greater production volume. The Company demonstrated this focus in February 2018, by announcing a 400% increase in the quarterly cash dividend to $0.25 per share, a $500 million expansion of its share-repurchase program, and its intent to reduce outstanding indebtedness by more than $1.0 billion by retiring 2018 and 2019 Anadarko debt maturities.

Anadarko currently estimates a 2018 initial capital spending range of $4.1 billion to $4.5 billion, excluding WES capital spending of approximately $1.0 billion to $1.1 billion. The Company has currently allocated approximately 86% of its 2018 capital spending budget to the U.S. onshore upstream and midstream and deepwater Gulf of Mexico; 8% to future value areas, which includes 5% to exploration and 3% to global LNG; 3% to international cash generation assets, such as oil projects in Algeria and Ghana; and 3% to corporate activities. The Company's repositioned asset footprint and strong balance sheet are built to deliver through future commodity cycles.

- ***Delaware Basin*** Anadarko plans to allocate approximately $1.0 billion toward upstream and an additional $500 million toward Anadarko midstream investments. This program supports the continuation of the Company's efforts to build out one of the most expansive and integrated infrastructure positions in the region. The Company also is advancing its efforts to capture operatorship on 70% of its acreage position, primarily in Reeves and Loving counties. Additionally, Anadarko continues to progress the construction of three ROTFs to support its more cost-effective and environmentally beneficial tankless battery design field-wide, while also securing necessary gathering, processing, and takeaway capacity. This comprehensive build-out plan and phased development approach in the basin is expected to deliver incremental oil sales volumes during the second half of 2018, with total-year Delaware basin oil sales volumes expected to increase more than 50% relative to 2017. During 2018, the Company plans to average seven operated rigs and six completion crews.

- ***DJ Basin*** Anadarko expects to invest approximately $950 million on upstream activities and an additional $50 million toward Anadarko midstream investments. The Company has implemented a new completion design in the field, which has resulted in a 20% improvement in average well recovery. Anadarko expects to increase year-over-year oil sales volumes from the DJ basin by more than 30% and plans to average five operated rigs and three completions crews in the basin during the year.

- ***Deepwater Gulf of Mexico*** Anadarko expects to allocate approximately $1.0 billion toward its deepwater Gulf of Mexico operations. The majority of these investments are expected to be directed toward high-return oil development opportunities near operated infrastructure at Lucius, Horn Mountain, Marlin, Holstein, and Marco Polo. The Company plans to operate two floating drillships and one platform rig and spud approximately nine development wells in the Gulf of Mexico during the year.

- ***International*** Anadarko plans to allocate approximately $150 million toward its international cash-generating operations in Algeria and Ghana. These investments will support further drilling in the TEN development area, which is expected to commence in early 2018, as well as additional drilling operations in the Jubilee field following the Ghanaian government's recent approval of the full-field plan of development.

- ***Exploration*** The Company's exploration investments in 2018 are expected to total approximately $200 million. Exploration spending will primarily be focused on the Gulf of Mexico, where the Company plans to drill identified prospects near existing operated infrastructure with one floating drillship. The Company plans to allocate additional exploration investment to the U.S. onshore as it continues to identify future areas that could make a material and scalable addition to its portfolio.

- ***LNG*** The Company expects to invest approximately $150 million to advance the Mozambique LNG project toward FID. This includes funding Anadarko's portion of the costs associated with preparing the site of the future onshore LNG park.

The Company announced a $2.5 billion share-repurchase program in September 2017, which was expanded to $3.0 billion in February 2018. The program is authorized through the end of 2018. During the fourth quarter of 2017, the Company repurchased 21.9 million shares for approximately $1.1 billion (average price of $48.33 per share) under an ASR Agreement and through open-market purchases. In February 2018, Anadarko completed a repurchase of 8.5 million shares for $500 million (average price of $58.82 per share) under an additional ASR Agreement. The Company plans to execute the remainder of the $3.0 Billion Share-Repurchase Program by the end of 2018.

In the fourth quarter of 2017, in order to reduce commodity-price risk and increase the predictability of 2018 cash flows, the Company entered into strategic derivative positions covering approximately 50% of its anticipated oil sales volumes for 2018. The Company entered into two-way collars for 108 MBbls/d, consisting of a sold call at $60.48 and a purchased put at $50.00 as well as fixed price swaps for 84 MBbls/d at an average price of $61.45. In January 2018, the Company entered into additional fixed-price swaps consisting of 280 MMBtu/d at an average price of $3.02, increasing its coverage to slightly more than 50% of its anticipated 2018 natural-gas sales volumes. See *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Subsequent to year end, the Company divested its nonoperated interest in Alaska for net proceeds of $383 million. The transaction is subject to regulatory approval.

2017 Overview To effectively manage the influence of potential commodity-price volatility, Anadarko continued to optimize and further concentrate its portfolio on higher-return, oil-levered opportunities in areas where it possesses both scale and competitive advantages, namely the Delaware and DJ basins in the U.S. onshore and deepwater Gulf of Mexico. Much of the 2017 operational and investment focus was preparing the Delaware basin for development with increased operatorship and infrastructure to facilitate long-term growth and value.

On December 22, 2017, the Tax Reform Legislation was signed into law. The Company recognized a one-time deferred tax benefit of $1.2 billion, inclusive of a $236 million increase to the Company's valuation allowance on its foreign tax credit carryforwards, due to the remeasurement of its U.S. deferred tax assets and liabilities based on the 21% corporate tax rate. The Company did not recognize U.S. income tax expense related to the deemed repatriation of its foreign income as required by the new legislation as any U.S. taxes will be offset with foreign tax credits. In a $60 WTI price environment, the Tax Reform Legislation is expected to reduce the Company's 2018 cash taxes by approximately $200 million.

Following a home explosion in Firestone, Colorado in April 2017, the Company took precautionary measures to shut in all operated vertical wells in the DJ basin to conduct additional inspections. It subsequently tested and permanently plugged, abandoned, and capped all one-inch return lines associated with these wells. In May 2017, the Colorado Oil & Gas Conservation Commission issued a two-phase Notice to Operators (NTO) requiring all operators to inventory and integrity test existing flowlines within 1,000 feet of a building unit and abandon all inactive flowlines in such areas. During the third quarter, the Company substantially completed the requirements of the NTO. In August 2017, following a three-month review of oil and gas operations, the Governor of Colorado announced several policy initiatives designed to enhance public safety, which are to be implemented through rulemaking or legislation. The Company continues to work cooperatively with state regulators and others and is also cooperating with the NTSB in its investigation related to the accident.

Significant 2017 operating and financial activities include the following:

Total Company

- The Company's oil sales volumes averaged 355 MBbls/d, representing a 12% increase from 2016, primarily due to increased volumes from the Gulf of Mexico, partially offset by the divestiture of certain U.S. onshore assets in 2017 and 2016.
- The Company's overall sales-volume product mix increased to 53% oil in 2017, compared to 40% in 2016, which significantly improved margins and returns.

U.S. Onshore

- Total sales volumes in the Delaware basin averaged 63 MBOE/d, representing a 41% increase from 2016, and oil sales volumes in the Delaware basin increased 13 MBbls/d, representing a 52% increase from 2016, primarily due to continued drilling and completion activities.
- WES acquired a third party's 50% nonoperated interest in the DBJV System in exchange for WES's 33.75% interest in nonoperated Marcellus midstream assets and $155 million in cash.
- The Company received net proceeds of approximately $4.0 billion from divestitures of certain U.S. onshore assets during 2017.

Gulf of Mexico

- Oil sales volumes averaged 121 MBbls/d, representing an 85% increase from 2016, primarily due to the GOM Acquisition and continued tie-back activity at several facilities, partially offset by deferred production as a result of Hurricanes Harvey, Irma, and Nate and nonoperated field downtime during the second half of 2017.

International

- The International Tribunal for the Law of the Sea issued a ruling in September 2017 regarding the delimitation of the maritime boundary between Ghana and Côte d'Ivoire in the Atlantic Ocean. The new maritime boundary as determined by the tribunal does not affect the TEN fields, and the operator now plans to resume development drilling in early 2018.
- Interim spread mooring of the FPSO at the Jubilee field in Ghana commenced in the fourth quarter of 2016 and was completed during the first quarter of 2017. In early 2018, the operator will start the first of three shutdown periods that are expected to occur in 2018 to effectively stabilize the turret and rotate the FPSO to its permanent heading. In October, the partnership received Ghanaian Government approval for the full-field plan of development, with drilling operations expected to commence in 2018.
- During the third quarter of 2017, the foundational legal and contractual framework was completed for the Company's onshore LNG project in Mozambique. Anadarko commenced resettlement and site preparation activities, which will position the onshore area for construction of the LNG facilities.
- Anadarko and its co-venturers in Offshore Area 1 in Mozambique reached agreement on the project's first long-term sale and purchase agreement for 2.6 MTPA with Thailand's national oil and gas company, subject to the approval of the Government of Thailand.

Financial

- The Company generated $4.0 billion of cash flow from operations and ended 2017 with $4.6 billion of cash.
- Prior to the end of 2017, the Company completed $1.1 billion of the share repurchases. In February 2018, the Company completed an additional $500 million of share repurchases.
- The Company recognized a one-time deferred tax benefit of $1.2 billion as a result of the Tax Reform Legislation.

FINANCIAL RESULTS

millions except per-share amounts	**2017**	2016	2015
Oil, natural-gas, and NGLs sales	**$ 8,969**	$ 7,153	$ 8,260
Gathering, processing, and marketing sales	**2,000**	1,294	1,226
Gains (losses) on divestitures and other, net	**939**	(578)	(788)
Revenues and other	**$ 11,908**	$ 7,869	$ 8,698
Costs and expenses	**12,580**	10,468	17,507
Other (income) expense	**1,016**	1,230	880
Income tax expense (benefit)	**(1,477)**	(1,021)	(2,877)
Net income (loss) attributable to common stockholders	**$ (456)**	$ (3,071)	$ (6,692)
Net income (loss) per common share attributable to common stockholders—diluted	**$ (0.85)**	$ (5.90)	$ (13.18)
Average number of common shares outstanding—diluted	**548**	522	508

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the year ended December 31, 2017," refer to the comparison of the year ended December 31, 2017, to the year ended December 31, 2016. Similarly, any increases or decreases "for the year ended December 31, 2016," refer to the comparison of the year ended December 31, 2016, to the year ended December 31, 2015. The primary factors that affect the Company's results of operations include commodity prices for oil, natural gas, and NGLs; sales volumes; the cost of finding and developing such reserves; and operating costs.

Revenues and Sales Volumes

millions	Oil	Natural Gas	NGLs	Total
2016 sales revenues	$ 4,668	$ 1,564	$ 921	$ 7,153
Changes associated with prices	**1,334**	**373**	**358**	**2,065**
Changes associated with sales volumes	**550**	**(589)**	**(210)**	**(249)**
2017 sales revenues	**$ 6,552**	**$ 1,348**	**$ 1,069**	**$ 8,969**
Increase/(decrease) vs. 2016	**40 %**	**(14)%**	**16%**	**25 %**
2015 sales revenues	$ 5,420	$ 2,007	$ 833	$ 8,260
Changes associated with prices	(745)	(241)	95	(891)
Changes associated with sales volumes	(7)	(202)	(7)	(216)
2016 sales revenues	$ 4,668	$ 1,564	$ 921	$ 7,153
Increase/(decrease) vs. 2015	(14)%	(22)%	11 %	(13)%

For 2017, the above table illustrates the effect of increases in commodity prices and changes associated with sales volumes. Sales volume changes during 2017 included increases related to assets acquired in the Gulf of Mexico in December 2016 (primarily oil) and decreases associated with U.S. onshore asset divestitures (primarily natural gas). For 2016, decreases in commodity prices were the main driver for the decrease in revenues.

The following provides Anadarko's sales volumes for the years ended December 31:

	2017	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
Barrels of Oil Equivalent					
(MMBOE except percentages)					
United States	**211**	(18)%	257	(5)%	272
International	**34**	3	33	(1)	33
Total barrels of oil equivalent	**245**	(16)	290	(5)	305
Barrels of Oil Equivalent per Day					
(MBOE/d except percentages)					
United States	**579**	(18)%	704	(5)%	745
International	**93**	4	89	(1)	91
Total barrels of oil equivalent per day	**672**	(15)	793	(5)	836

Sales volumes represent actual production volumes adjusted for changes in commodity inventories as well as natural-gas production volumes provided to satisfy a commitment under the Jubilee development plan in Ghana. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. Production of oil, natural gas, and NGLs is usually not affected by seasonal swings in demand.

Oil Sales Revenues, Average Prices, and Volumes

	2017	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
Oil sales revenues (millions)	**$ 6,552**	40%	$ 4,668	(14)%	$ 5,420
United States					
Sales volumes—MMBbls	**97**	14%	85	1 %	85
MBbls/d	**266**	14	233	1	232
Price per barrel	**$ 49.62**	27	$ 39.06	(13)	$ 45.00
International					
Sales volumes—MMBbls	**32**	6%	31	(2)%	31
MBbls/d	**89**	6	83	(2)	85
Price per barrel	**$ 53.77**	22	$ 43.93	(15)	$ 51.68
Total					
Sales volumes—MMBbls	**129**	12%	116	— %	116
MBbls/d	**355**	12	316	—	317
Price per barrel	**$ 50.66**	26	$ 40.34	(14)	$ 46.79

The following summarizes primary drivers for the change in oil sales revenues:

millions	Change in Revenues	Due to Change in Prices	Due to Change in Volumes
2017 vs. 2016	$ 1,884	$ 1,334	$ 550
2016 vs. 2015	(752)	(745)	(7)

Oil Prices

The average oil price Anadarko received decreased from 2015 through late 2016, primarily due to continued high petroleum inventories globally and stronger supply growth from OPEC. Oil prices increased in late 2016 through 2017 primarily due to the expectation of decreasing global oversupply as a result of OPEC's agreement to reduce production through the end of 2018.

Oil Sales Volumes

2017 vs. 2016 The Company's oil sales volumes increased by 39 MBbls/d, primarily due to the following:

U.S. Onshore

- Sales volumes for the Delaware basin increased by 13 MBbls/d, primarily due to continued drilling and completion activities in 2017.
- Divestitures resulted in a decrease in sales volumes of 29 MBbls/d, primarily related to the sale of the Eagleford assets in the first half of 2017.

Gulf of Mexico

- Sales volumes increased by 56 MBbls/d, primarily due to the GOM Acquisition in December 2016 and continued tie-back activity at several facilities, partially offset by deferred production as a result of Hurricanes Harvey, Irma, and Nate and nonoperated field downtime during the second half of 2017.

International

- Sales volumes for Ghana increased by 9 MBbls/d, primarily due to a full year of liftings from the TEN development project, which came online late in the third quarter of 2016, and downtime in 2016 to address new production and offtake procedures resulting from issues associated with the Jubilee field FPSO turret bearing. Shuttle tankers are conducting offtakes until the facility is permanently moored.

2016 vs. 2015 The Company's oil sales volumes remained relatively flat.

U.S. Onshore

- Sales volumes for the Delaware basin increased by 8 MBbls/d, primarily due to continued field development.
- Sales volumes for the DJ basin decreased by 6 MBbls/d, primarily due to reduced capital activity.
- Sales volumes decreased by 7 MBbls/d, primarily due to the sale of EOR assets in the first half of 2015 and the East Chalk and Wamsutter assets in the first half of 2016.

Gulf of Mexico

- Sales volumes increased by 12 MBbls/d, primarily due to new wells coming online at K2 Complex and Caesar/Tonga in the first half of 2016, an increased flow rate at Lucius, and the achievement of first oil at Heidelberg in January 2016.

International

- Sales volumes for Ghana decreased by 7 MBbls/d, primarily due to downtime during 2016 to address new production and offtake procedures resulting from issues associated with the Jubilee field FPSO turret bearing. Shuttle tankers are conducting offtakes until the facility is permanently moored. The decrease in volumes at Jubilee were partially offset by TEN coming online late in the third quarter of 2016.

Natural-Gas Sales Revenues, Volumes, and Average Prices

	2017	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
Natural-gas sales revenues (millions)	**$ 1,348**	(14)%	$ 1,564	(22)%	$ 2,007
United States					
Sales volumes—Bcf	**478**	(38)%	766	(10)%	852
MMcf/d	**1,309**	(37)	2,093	(10)	2,334
Price per Mcf	**$ 2.82**	38	$ 2.04	(14)	$ 2.36

The following summarizes primary drivers for the change in natural-gas sales revenues:

millions	Change in Revenues	Due to Change in Prices	Due to Change in Volumes
2017 vs. 2016	$ (216)	$ 373	$ (589)
2016 vs. 2015	(443)	(241)	(202)

Natural-Gas Prices

The average natural-gas price Anadarko received decreased from 2015 through late 2016, primarily due to high gas storage levels in 2016. The increase in storage levels was a result of strong production growth in 2015 coupled with lower weather-driven residential and commercial demand in late 2015 and early 2016. This decrease was slightly offset by an increase in exports to Mexico throughout 2015 and 2016. The price increased year-over-year from 2016 to 2017 primarily due to a reduction of natural-gas storage industry-wide resulting from production declines across the industry from mid-2016 through early 2017 and stable exports to Mexico throughout 2017.

Natural-Gas Sales Volumes

2017 vs. 2016 The Company's natural-gas sales volumes decreased by 784 MMcf/d, primarily due to the sale of the Marcellus and Eagleford assets in the first half of 2017, the Carthage and Elm Grove assets in the second half of 2016, and the Wamsutter assets in the first half of 2016.

2016 vs. 2015 The Company's natural-gas sales volumes decreased by 241 MMcf/d primarily due to the following:

U.S. Onshore

- Sales volumes for the DJ basin increased by 98 MMcf/d, primarily due to improved performance.
- Sales volumes for the Delaware basin increased by 18 MMcf/d, primarily due to continued field development.
- Sales volumes decreased by 290 MMcf/d, primarily due to the sale of the Powder River Basin CBM assets and the Freestone assets in the second half of 2015, the Carthage assets in the second half of 2016, and the Wamsutter assets in the first half of 2016.

Gulf of Mexico

- Sales volumes decreased by 61 MMcf/d, primarily as a result of the last producing well at Independence Hub going off line in December 2015.

Natural-Gas Liquids Sales Revenues, Volumes, and Average Prices

	2017	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
Natural-gas liquids sales revenues (millions)	**$ 1,069**	16 %	$ 921	11 %	$ 833
Total					
Sales volumes—MMBbls [(1)]	**36**	(23)%	46	(1)%	47
MBbls/d [(2)]	**99**	(23)	128	(1)	130
Price per barrel	**$ 29.54**	50	$ 19.64	12	$ 17.61

(1) The percentage of NGLs sales volumes from the U.S. was 94% in 2017 and 96% in 2016 and 2015.
(2) The percentage of daily NGLs sales volumes from the U.S. was 96% in 2017 and 95% in 2016 and 2015.

The following summarizes primary drivers for the change in NGLs sales revenues:

millions	Change in Revenues	Due to Change in Prices	Due to Change in Volumes
2017 vs. 2016	$ 148	$ 358	$ (210)
2016 vs. 2015	88	95	(7)

NGLs Prices

The average NGLs price Anadarko received increased from 2015 to 2017, primarily due to increased ethane and propane prices stemming from higher exports and increased domestic demand.

NGLs Sales Volumes

2017 vs. 2016 The Company's NGLs sales volumes decreased by 29 MBbls/d, primarily due to the sale of the Eagleford assets in the first half of 2017 and the Carthage assets in the second half of 2016.

2016 vs. 2015 The Company's NGLs sales volumes were relatively flat.

Gathering, Processing, and Marketing

millions except percentages	**2017**	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
Gathering, processing, and marketing sales	**$ 2,000**	55%	$ 1,294	6%	$ 1,226
Gathering, processing, and marketing expense	**1,560**	44	1,087	3	1,054
Total gathering, processing, and marketing, net	**$ 440**	113	$ 207	20	$ 172

Gathering and processing sales include revenue from the sale of NGLs and remaining residue gas extracted from natural gas purchased from third parties and processed by Anadarko as well as fee revenue earned by providing gathering, processing, compression, and treating services to third parties. Gathering and processing expense includes the cost of third-party natural gas purchased and processed by Anadarko as well as other operating and transportation expenses related to the Company's costs to perform gathering and processing activities. Beginning in 2018, gathering and processing sales and expenses are expected to be impacted by ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. See Note 1—Summary of Significant Accounting Policies in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for further information.

Marketing sales include the margin earned from purchasing and selling third-party oil and natural gas. Marketing expense includes transportation and other operating expenses related to the Company's costs to perform marketing activities.

2017 vs. 2016 Gathering, processing, and marketing, net increased by $233 million. This increase primarily related to higher throughput volumes and prices at the DBM Complex due to increased processing capacity from the start-up of newly constructed facilities in May and October 2016 and previously existing facilities returning to service after the 2016 outage at the DBM Complex.

2016 vs. 2015 Gathering, processing, and marketing, net increased by $35 million. This increase primarily related to higher gas and NGLs throughput volumes at the DJ basin and DBM Complex.

Gains (Losses) on Divestitures and Other, net

millions except percentages	**2017**	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
Gains (losses) on divestitures, net	**$ 674**	189%	$ (757)	26%	$ (1,022)
Other	**265**	48	179	(24)	234
Total gains (losses) on divestitures and other, net	**$ 939**	NM	$ (578)	27	$ (788)

Gains (losses) on divestitures and other, net includes gains (losses) on divestitures and other operating revenues, including hard-minerals royalties, earnings from equity investments, and other revenues.

During the years presented, Anadarko divested of certain non-core U.S. onshore assets. See Note 3—Acquisitions, Divestitures, and Assets Held for Sale in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Costs and Expenses

The following provides Anadarko's total costs and expenses for the years ended December 31:

millions	**2017**	2016	2015
Oil and gas operating	**$ 1,000**	$ 811	$ 1,014
Oil and gas transportation	**914**	1,002	1,117
Exploration	**2,541**	946	2,644
Gathering, processing, and marketing	**1,560**	1,087	1,054
G&A	**1,075**	1,440	1,176
DD&A	**4,279**	4,301	4,603
Production, property, and other taxes	**582**	536	553
Impairments	**408**	227	5,075
Other operating expense	**221**	118	271
Total	**$ 12,580**	$ 10,468	$ 17,507

Oil and Gas Operating and Transportation Expenses

	2017	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
Oil and gas operating (millions)	**$ 1,000**	23%	$ 811	(20)%	$ 1,014
Oil and gas operating—per BOE	**4.08**	46	2.79	(16)	3.32
Oil and gas transportation (millions)	**914**	(9)	1,002	(10)	1,117
Oil and gas transportation—per BOE	**3.73**	8	3.46	(5)	3.66

Oil and Gas Operating Expenses

2017 vs. 2016 Oil and gas operating expenses increased by $189 million primarily due to the following:

- higher operating costs of $212 million primarily related to the GOM Acquisition
- higher operating costs of $88 million related to increased activity in the DJ and Delaware basins and costs related to the Company's response efforts in Colorado in 2017
- lower nonoperating costs of $12 million in Ghana primarily related to FPSO maintenance costs in 2016, partially offset by higher costs in 2017 due to increased production from the TEN development, which came online late in the third quarter of 2016
- lower expenses of $89 million as a result of U.S. onshore asset divestitures

The related costs per BOE increased by $1.29 primarily due to increased costs as a result of shifting to a higher-return, oil-levered portfolio that includes the Gulf of Mexico and Delaware basin, which operate at a higher cost compared to the lower-return, gas-levered divested assets.

2016 vs. 2015 Oil and gas operating expenses decreased by $203 million primarily due to the following:

- lower workover costs of $28 million in the Gulf of Mexico and the U.S. onshore
- lower surface maintenance costs of $16 million in the U.S. onshore and the Gulf of Mexico
- lower expenses of $112 million as a result of divestitures

Oil and Gas Transportation Expenses

2017 vs. 2016 Oil and gas transportation expenses decreased by $88 million primarily due to 2017 and 2016 U.S. onshore divestitures, partially offset by increased oil and gas sales volumes in the Gulf of Mexico and increased rates at DJ basin. Oil and gas transportation expenses per BOE increased by $0.27 primarily due to increased oil and natural-gas transportation rates at DJ basin.

2016 vs. 2015 Oil and gas transportation expenses decreased by $115 million due to overall lower natural-gas sales volumes attributable to divestitures. Oil and gas transportation expenses per BOE decreased by $0.20 primarily due to lower costs as a result of lower natural-gas sales volumes.

Exploration Expense

millions	**2017**	2016	2015
Dry hole expense	**$ 1,433**	$ 397	$ 1,052
Impairments of unproved properties	**788**	216	1,215
Geological and geophysical, exploration overhead, and other expense	**320**	333	377
Total exploration expense	**$ 2,541**	$ 946	$ 2,644

Dry Hole Expense

2017

- $437 million related to the Shenandoah project, $215 million related to the Phobos project, and $108 million related to the Warrior project in the Gulf of Mexico due to insufficient quantities of oil pay to justify development
- $329 million related to all remaining wells in Côte d’Ivoire, where the Company relinquished its interest in its Cote d'Ivoire blocks
- $243 million related to certain wells in the Grand Fuerte area in Colombia due to insufficient progress on contractual and fiscal reforms needed for deepwater natural-gas development

2016

- $231 million related to certain wells in the Gulf of Mexico and $92 million related to certain wells in Mozambique
- $39 million for a well in Côte d’Ivoire that finished drilling in the third quarter of 2016 and encountered noncommercial quantities of hydrocarbons

2015

- $746 million primarily related to Brazil where the Company did not expect to have substantive exploration and development activities for the foreseeable future given the current oil-price environment
- $306 million due to unsuccessful drilling activities in 2015 primarily in Colombia and the Gulf of Mexico

See *Note 6—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Impairments of Unproved Properties

2017

- The Company recognized a $610 million impairment of unproved Gulf of Mexico properties, of which $463 million related to the Shenandoah project. The unproved property balance related to the Shenandoah project originated from the purchase price allocated to the Gulf of Mexico exploration projects from the acquisition of Kerr McGee Corporation in 2006. For additional details on the Shenandoah project, see *Note 6—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.
- The Company recognized $88 million of impairments of unproved international properties.

2016

- The Company recognized a $72 million impairment of unproved properties in the Gulf of Mexico and $92 million for unproved international properties, primarily in Brazil and Tunisia, due to the Company's current intentions to not pursue future exploration activities.

2015

- The Company recognized a $935 million impairment of unproved Greater Natural Buttes properties and a $66 million impairment of an unproved Gulf of Mexico property as a result of lower commodity prices.
- The Company recognized a $109 million impairment of unproved Utica properties resulting from an assignment of mineral interests in settlement of a legal matter.

G&A

millions except percentages	**2017**	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
G&A	**$ 1,075**	(25)%	$ 1,440	22%	$ 1,176

2017 vs. 2016 G&A decreased by $365 million for the year ended December 31, 2017. Excluding $389 million of charges recorded in 2016 associated with the workforce reduction program, G&A remained relatively flat. See *Note 18—Restructuring Charges* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

2016 vs. 2015 G&A for the year ended December 31, 2016, included $389 million of charges associated with a workforce reduction program initiated in March 2016. Excluding the workforce reduction expenses, G&A decreased by $125 million primarily due to lower employee-related expenses resulting from the workforce reduction.

DD&A

millions except percentages	**2017**	Inc (Dec) vs. 2016	2016	Inc (Dec) vs. 2015	2015
DD&A	**$ 4,279**	(1)%	$ 4,301	(7)%	$ 4,603

2017 vs. 2016 DD&A expense decreased by $22 million, primarily due to the following:

- $717 million related to lower 2017 sales volumes and asset property balances associated with U.S. onshore properties as a result of divestitures in 2016 and 2017

These decreases were offset by the following:

- $457 million related to higher sales volumes in the Gulf of Mexico primarily due to the GOM Acquisition
- $240 million related to international production DD&A primarily due to higher sales volumes from the Ghana TEN project, which came online late in the third quarter of 2016

2016 vs. 2015 DD&A expense decreased by $302 million, primarily due to the following:

- lower carrying value for U.S. onshore and midstream properties as a result of 2015 asset impairments and divestitures in 2015 and 2016
- lower 2016 sales volumes associated with U.S. onshore properties

Impairments

The Company recognized the following impairments for the years ended December 31:

millions	**2017**	2016	2015
Exploration and Production			
U.S. onshore properties	**$ 2**	$ 28	$ 3,684
Gulf of Mexico properties	**227**	27	349
Cost-method investment	**—**	59	3
WES Midstream	**176**	16	515
Other Midstream	**2**	57	524
Other	**1**	40	—
Total impairments [1]	**$ 408**	$ 227	$ 5,075

[1] In 2015, $3.0 billion of Exploration and Production impairments and $482 million of Other Midstream impairments related to Greater Natural Buttes.

See *Note 5—Impairments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on impairments and *Risk Factors* under Item 1A of this Form 10-K for further discussion on the risks associated with oil, natural-gas, and NGLs prices.

Other (Income) Expense

The following provides Anadarko's other (income) expense for the years ended December 31:

millions	**2017**	2016	2015
Interest expense [(1)]	**$ 932**	$ 890	$ 825
Loss on early extinguishment of debt [(2)]	**2**	155	—
(Gains) losses on derivatives, net [(3)]	**135**	286	(99)
Other (income) expense, net	**(53)**	(101)	154
Total	**$ 1,016**	$ 1,230	$ 880

(1) The increase in interest expense from 2016 to 2017 is primarily due to lower capitalized interest in 2017. See *Note 12—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) See *Note 12—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for information on early extinguishment of debt.

(3) See *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Income Tax Expense (Benefit)

Total income taxes differed from the amounts computed by applying the U.S. federal statutory income tax rate to income (loss) before income taxes. The following summarizes the sources of these differences for the years ended December 31:

millions except percentages	**2017**	2016	2015
Income tax expense (benefit)	**$ (1,477)**	$ (1,021)	$ (2,877)
Income (loss) before income taxes	**$ (1,688)**	$ (3,829)	$ (9,689)
Effective tax rate	**88%**	27%	30%

In 2017, as a result of the Tax Reform Legislation, the Company recognized a one-time deferred tax benefit of $1.2 billion primarily due to the remeasurement of its U.S. deferred tax assets and liabilities, resulting in an 88% effective tax rate. Excluding this one-time benefit, the Company's effective tax rate would have been 18%.

The Company's effective tax rate is impacted each year by the relative pretax income earned by the Company's operations in the U.S., Algeria, and the rest of the world. Additionally, the Company's effective tax rate is typically impacted by state income taxes (net of federal benefit), non-deductible Algerian exceptional profits tax for Algerian income tax purposes, net changes in uncertain tax positions, and dispositions of non-deductible goodwill. Excluding the one-time benefit related to the Tax Reform Legislation in 2017, the Company's effective tax rate decreased from 27% in 2016 to 18% in 2017, primarily due to the higher-taxed income earned in Algeria relative to the Company's pretax losses in the U.S. and Ghana as well as the impact of international exploration pretax losses with no associated tax benefit. The Company's effective tax rate decreased from 30% in 2015 to 27% in 2016 primarily due to the reversal of non-deductible goodwill due to asset divestitures in 2016.

The Company generated a net operating loss in 2016 and filed a carryback claim for a tax refund of $159 million, which was received in December 2017.

The Company received an $881 million tentative refund in 2016 related to its $5.2 billion Tronox settlement payment in 2015. The IRS has issued a draft notice of proposed adjustment denying the deductibility of the settlement payment. If the payment is ultimately determined to not be deductible, the Company would be required to repay the tentative refund previously received plus interest, and the Company would be required to reverse the net benefit of $346 million previously recognized in its financial statements.

For additional information on income taxes, see *Note 13—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

LIQUIDITY AND CAPITAL RESOURCES

millions	**2017**	2016	2015
Net cash provided by (used in) operating activities	**$ 4,009**	$ 3,000	$ (1,877)
Net cash provided by (used in) investing activities	**(1,028)**	(2,762)	(4,771)
Net cash provided by (used in) financing activities	**(1,613)**	2,008	220

Overview The Company has a variety of funding sources available, including cash, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements that reduce future capital expenditures, the Company's credit facilities, and access to both debt and equity capital markets. In addition, an effective registration statement is available to Anadarko covering the sale of WGP common units owned by the Company. WGP and WES function with capital structures that are separate from Anadarko, consisting of their own debt instruments and publicly traded common units.

During 2017, Anadarko received net proceeds of $4.0 billion from divestitures, primarily related to the sale of the Company's Eagleford, Marcellus, Eaglebine, Utah CBM, and Moxa assets. As of December 31, 2017, Anadarko had $4.6 billion of cash plus $5.0 billion of borrowing capacity under its RCFs. In January 2018, the Company received net proceeds of $383 million from the divestiture of its nonoperated interest in Alaska. Anadarko believes that its current available cash and anticipated operating cash flows will be sufficient to fund the Company's projected long-term operational and capital programs as well as to fund the increase in dividends to $0.25 per share, to repurchase the remaining shares under the $3.0 Billion Share-Repurchase Program by the end of 2018, and to retire Anadarko's debt maturing in 2018 and 2019. In a $60 WTI price environment, the Tax Reform Legislation is expected to reduce the Company's 2018 cash taxes by approximately $200 million. The Company continuously monitors its liquidity position and evaluates available funding alternatives in light of current and expected conditions.

Credit Rating As of December 31, 2017, the Company's long-term debt was rated investment grade (BBB) by both S&P and Fitch and below investment grade (Ba1) by Moody's. As a result of Moody's rating, Anadarko is more likely to be required to post collateral in the form of letters of credit or cash under certain contractual arrangements such as derivative instruments, pipeline transportation contracts, and oil and gas sales contracts. Collateral related to credit-risk-related contingent features for which a net liability position existed was $170 million at December 31, 2017, and $117 million at December 31, 2016. For more information on credit-risk considerations, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. The amount of letters of credit or cash provided as assurance of the Company's performance under pipeline transportation contracts and oil and gas sales contracts with respect to credit-risk-related contingent features was $263 million at December 31, 2017, and $274 million at December 31, 2016.

Operating Activities

One of the primary sources of variability in the Company's cash flows from operating activities is the fluctuation in commodity prices, the impact of which Anadarko partially mitigates by periodically entering into commodity derivatives. Sales volume changes also impact cash flow but historically have not been as volatile as commodity prices. Anadarko's cash flows from operating activities are also impacted by the costs related to operations and interest payments related to the Company's outstanding debt.

Cash flows from operating activities for 2016 were impacted by several significant items, including the $159.5 million payment of the Clean Water Act (CWA) penalty, $247 million related to severance costs and retirement benefits paid in connection with the workforce reduction program, and the receipt of an $881 million tax refund related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback. Excluding these 2016 items, cash flows from operating activities for 2017 were $1.5 billion higher compared to 2016, primarily as a result of higher sales revenues due to the impact of higher commodity prices.

Cash flows from operating activities for 2015 were impacted by the $5.2 billion Tronox settlement payment. Excluding the Tronox settlement payment in 2015 and the significant 2016 items mentioned above, cash flows from operating activities for 2016 were $813 million lower compared to 2015, primarily as a result of lower sales revenues due to the impact of lower commodity prices.

See *Note 13—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion related to the potential repayment of the 2016 tax refund.

Pension and Other Postretirement Contributions Contributions to the pension and other postretirement plans were $276 million in 2017, $120 million in 2016, and $58 million in 2015. The Company expects to contribute $152 million in 2018 to its pension and other postretirement plans.

Investing Activities

Capital Expenditures The following presents the Company's capital expenditures:

millions	**2017**	2016	2015
Cash Flows from Investing Activities			
Additions to properties and equipment [1]	**$ 5,031**	$ 3,505	$ 6,067
Adjustments for capital expenditures			
Changes in capital accruals	**275**	(205)	(226)
Other	**(6)**	14	47
Total capital expenditures [2]	**$ 5,300**	$ 3,314	$ 5,888
Exploration and Production and other capital expenditures	**$ 3,886**	$ 2,764	$ 5,118
WES Midstream capital expenditures	**956**	491	525
Other Midstream capital expenditures	**458**	59	245

(1) Additions to properties and equipment as presented within Anadarko's cash flows from investing activities include cash payments for cost of properties, equipment, and facilities. The cost of properties includes the initial capitalization of drilling costs associated with all exploratory wells, whether or not they were deemed to have a commercially sufficient quantity of proved reserves.

(2) Capital expenditures exclude the FPSO capital lease asset; see Financing Activities—*Capital Lease Obligations* below.

2017 vs. 2016 The Company's capital expenditures increased by $2.0 billion for the year ended December 31, 2017. Exploration and Production capital expenditures increased primarily due to higher development costs of $917 million driven by increased U.S. onshore drilling activity primarily in the DJ basin and operatorship capture in the Delaware basin as well as higher exploration costs of $363 million primarily driven by U.S. onshore acreage acquisitions and $172 million primarily due to exploration drilling in the Gulf of Mexico. These increases were partially offset by decreased development costs of $227 million driven by the TEN development project in Ghana, which achieved first oil in the third quarter of 2016. WES Midstream capital expenditures increased primarily due to $465 million related to the development of assets primarily in the Delaware and DJ basins. Other Midstream capital expenditures increased $399 million due to asset development primarily in the Delaware basin.

2016 vs. 2015 The Company's capital expenditures decreased by $2.6 billion for the year ended December 31, 2016. Exploration and Production capital expenditures decreased primarily due to reduced development and exploration activity, resulting in decreased development costs of $2.1 billion primarily in the U.S. onshore and decreased exploration costs of $432 million primarily in the U.S. onshore, Colombia, and Mozambique. These decreases were partially offset by increased exploration costs of $251 million primarily due to exploration drilling in the Gulf of Mexico and Côte d'Ivoire. Other Midstream capital expenditures decreased by $186 million and WES Midstream capital expenditures decreased by $34 million primarily due to reduced development activity.

Property Exchange On March 17, 2017, WES acquired a third party's 50% nonoperated interest in the DBJV System in exchange for WES's 33.75% interest in nonoperated Marcellus midstream assets and $155 million in cash. WES funded the cash consideration with cash on hand and recognized a gain of $126 million as a result of this transaction. After the acquisition, the DBJV System is 100% owned by WES and consolidated by Anadarko. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Acquisitions In December 2016, the Company closed the GOM Acquisition for $1.8 billion. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Divestitures Anadarko received net proceeds from property divestitures of $4.0 billion in 2017, $2.4 billion in 2016, and $1.4 billion in 2015. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Financing Activities

millions except percentages	**2017**	2016
Anadarko	**$ 12,196**	$ 12,204
WES	**3,465**	3,091
WGP	**28**	28
Total debt	**$ 15,689**	$ 15,323
Total equity	**13,790**	15,497
Debt to total capitalization ratio	**53.2%**	49.7%

Debt Activity The following summarizes the Company's borrowing activity:

millions	**2017**	2016	2015	**Description**
Issuances	**$ —**	$ 800	$ —	4.850% Senior Notes due 2021 [(1)]
	—	1,100	—	5.550% Senior Notes due 2026 [(1)]
	—	1,100	—	6.600% Senior Notes due 2046 [(1)]
	—	500	—	WES 4.650% Senior Notes due 2026
	—	—	500	WES 3.950% Senior Notes due 2025
	—	—	101	TEUs - senior amortizing notes
	—	200	—	WES 5.450% Senior Notes due 2044
Borrowings	**—**	1,750	1,800	364-Day Facility
	—	—	1,500	$5.0 Billion Facility
	370	600	400	WES RCF
	—	28	—	WGP RCF
	—	—	250	Commercial paper notes, net [(2)]
Repayments	**(6)**	—	—	7.000% Debentures due 2027
	(3)	—	—	6.625% Debentures due 2028
	(1)	—	—	7.950% Debentures due 2029
	—	(1,750)	—	5.950% Senior Notes due 2016
	—	(2,000)	—	6.375% Senior Notes due 2017
	—	(1,750)	(1,800)	364-Day Facility
	—	—	(1,500)	$5.0 Billion Facility
	—	(900)	(610)	WES RCF
	—	(250)	—	Commercial paper notes, net
	(34)	(34)	(16)	TEUs - senior amortizing notes

(1) Represent senior notes issued in March 2016.
(2) Includes repayments of $(106) million related to commercial paper notes with maturities greater than 90 days.

Senior Notes During the second quarter of 2016, the Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. In December 2016, the Company redeemed its remaining $750 million 6.375% Senior Notes due September 2017. The Company recognized losses of $155 million for the early retirement and redemption of these senior notes, which included $144 million of premiums paid.

In July 2016, WES completed a public offering of $500 million aggregate principal amount of 4.650% Senior Notes due July 2026. Net proceeds were used to repay a portion of the amount outstanding under the WES RCF. In October 2016, WES completed a public offering of $200 million aggregate principal amount of 5.450% Senior Notes due April 2044. Net proceeds were primarily used to repay amounts outstanding under the WES RCF and the remaining proceeds were used for general partnership purposes, including capital expenditures. In 2015, net proceeds from the WES 3.950% Senior Notes were used to repay WES RCF borrowings.

Anadarko RCFs At December 31, 2017, Anadarko had no outstanding borrowings under its $3.0 billion senior unsecured RCF (APC RCF) or its $2.0 billion 364-day senior unsecured RCF (364-Day Facility). In January 2018, the Company amended the APC RCF to extend the maturity date to January 2022 and amended the 364-Day Facility to extend the maturity date to January 2019.

WES and WGP RCFs At December 31, 2017, WES had a $1.2 billion RCF that matures in February 2020 and is expandable to $1.5 billion. During 2017, WES borrowed $370 million under its RCF, which was used for general partnership purposes. At December 31, 2017, WES had $370 million outstanding borrowings under its RCF at an interest rate of 2.87%, had outstanding letters of credit of $5 million, and had available borrowing capacity of $825 million. In February 2018, the WES RCF was amended to extend the maturity date from February 2020 to February 2023 and expand the borrowing capacity to $1.5 billion.

During 2017, WGP had a $250 million RCF that matures in March 2019 and is expandable to $500 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions. At December 31, 2017, WGP had outstanding borrowings under its RCF of $28 million at an interest rate of 3.57% and had available borrowing capacity of $222 million. In February 2018, WGP voluntarily reduced the aggregate commitments of the lenders under the WGP RCF to $35 million.

For additional information on the Company's RCFs, such as years of maturity, interest rates, and covenants, see *Note 12—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Commercial Paper Program The Company has a commercial paper program, which allows for a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the APC RCF. As a result of Moody's credit rating on Anadarko, the Company's access to the commercial paper market has been eliminated. The Company repaid $250 million of commercial paper notes during the first quarter of 2016, and there were no outstanding borrowings under the commercial paper program at December 31, 2017. See *Note 12—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Debt Maturities At December 31, 2017, Anadarko's scheduled debt maturities during 2018 consisted of $17 million of senior amortizing notes associated with the TEUs and $114 million of 7.05% Debentures due May 2018. In addition, WES has a scheduled debt maturity during 2018 of $350 million of 2.600% Senior Notes due August 2018. WES's $350 million 2.600% Senior Notes due August 2018 were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2017, as WES has the ability and intent to refinance these obligations using long-term debt. Anadarko's Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value of the outstanding Zero Coupons. None of the Zero Coupons were put to the Company in October 2017. The Zero Coupons can next be put to the Company in October 2018, in whole or in part, for the then-accreted value of $930 million.

For additional information on the Company's debt instruments and capital lease obligations, such as transactions during the period, years of maturity, and interest rates, see *Note 12—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Capital Lease Obligations Construction of the FPSO for the Company's TEN field operations in Ghana commenced in 2013. The Company recognized an asset and related obligation during the construction period for its pro-rata share. Upon completion of the construction during the third quarter of 2016, the Company reported the asset and related obligation as a capital lease of $225 million for the Company's share of the fair value of the FPSO based on the operator's lease agreement. The Company made capital lease payments of $44 million in 2017. Anadarko's scheduled payments for 2018 associated with capital lease obligations are $53 million. Principal payments related to capital lease obligations are reported in financing activities and interest payments related to capital lease obligations are reported in operating activities on the Company's Consolidated Statement of Cash Flows. See *Note 12—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Equity Transactions During the fourth quarter of 2017, the Company completed approximately $1.1 billion of the $3.0 Billion Share-Repurchase Program by repurchasing 21.9 million shares (average price of $48.33 per share) under an ASR Agreement and through open-market purchases. In February 2018, Anadarko completed a repurchase of 8.5 million shares for $500 million (average price of $58.82 per share) under an additional ASR Agreement. The Company expects to execute the remainder of the program by the end of 2018. For additional information, see *Note 20—Stockholders' Equity* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

In September 2016, Anadarko completed a public offering of 40.5 million shares of its common stock for net proceeds of $2.16 billion. Net proceeds were primarily used to fund the GOM Acquisition, with the remainder used for general corporate purposes.

Anadarko sold 12.5 million of its WGP common units to the public for net proceeds of $476 million in 2016 and 2.3 million WGP common units to the public for net proceeds of $130 million in 2015. The proceeds for all periods were used for general corporate purposes. At December 31, 2017, Anadarko owned 179 million WGP common units, which represents an 81.6% interest in WGP.

During 2016, WES issued 22 million Series A Preferred units to private investors for net proceeds of $687 million. In July 2017, WES filed a registration statement with the SEC for the issuance of up to an aggregate of $500 million of WES common units under a continuous offering program that has not yet been initiated. Pursuant to WES's registration statement filed with the SEC in August 2014 authorizing the issuance of up to an aggregate of $500 million of WES common units, WES issued approximately 874 thousand common units to the public and raised net proceeds of $57 million during 2015. The proceeds were used for general partnership purposes, including capital expenditures.

During the second quarter of 2015, Anadarko issued 9.2 million 7.50% TEUs at a stated amount of $50.00 per TEU and raised net proceeds of $445 million. Each TEU is comprised of a prepaid equity purchase contract for WGP common units, subject to Anadarko's right to elect to issue and deliver shares of Anadarko's common stock in lieu of WGP common units, and a senior amortizing note due in June 2018. See *Note 11—Tangible Equity Units* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Derivative Instruments Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio is subject to changes in interest rates. Net cash payments related to settlements and amendments of interest-rate swap agreements were $112 million in 2017 and $274 million in 2016. For information on derivative instruments, including cash flow treatment, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Conveyance of Future Hard-Minerals Royalty Revenues During the first quarter of 2016, the Company conveyed a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party for $413 million, net of transaction costs. The Company made payments for royalties of $50 million in 2017 and $25 million in 2016. For additional information on the cash flow treatment, expected timing, and scheduled payments of the conveyed royalties, see *Note 15—Conveyance of Future Hard-Minerals Royalty Revenues* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Common Stock Dividends Anadarko paid dividends to its common stockholders of $111 million in 2017, $105 million in 2016, and $553 million in 2015. In response to the commodity-price environment, the Company decreased the quarterly dividend from $0.27 per share to $0.05 per share in February 2016. In February 2018, the Company announced an increase in the quarterly dividend to $0.25 per share. Anadarko has paid a dividend to its common stockholders quarterly since becoming a public company in 1986.

The amount of future dividends paid to Anadarko common stockholders is determined by the Board on a quarterly basis and is based on the Company's earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors deemed relevant by the Board.

Distributions to Noncontrolling Interest Owners Distributions to noncontrolling interest owners primarily relate to the following:

millions	**2017**	2016	2015
WES distributions to unitholders (excluding Anadarko and WGP) (1)	**$ 326**	$ 258	$ 231
WES distributions to Series A Preferred unitholders (2)	**22**	31	—
WGP distributions to unitholders (excluding Anadarko) (3)	**81**	59	37

(1) WES has made quarterly distributions to its unitholders since its IPO in the second quarter of 2008 and has increased its distribution from $0.30 per common unit for the third quarter of 2008 to $0.92 per common unit for the fourth quarter of 2017 (paid in February 2018).

(2) WES made distributions of $0.68 per unit, prorated based on issuance date, to its Series A Preferred unitholders since the unit issuances in March and April 2016. As of June 30, 2017, all Series A Preferred units had converted into WES common units. See *Note 23—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(3) WGP has made quarterly distributions to its unitholders since its IPO in December 2012 and has increased its distribution from $0.17875 per common unit for the first quarter of 2013 to $0.54875 per unit for the fourth quarter of 2017 (to be paid in February 2018).

Insurance Coverage and Other Indemnities

Anadarko maintains property and casualty insurance that includes coverage for physical damage to the Company's properties, blowout/control of a well, restoration and redrill, sudden and accidental pollution, third-party liability, workers' compensation and employers' liability, and other risks. Anadarko's insurance coverage includes deductibles that must be met prior to recovery. Additionally, the Company's insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect the Company against liability or loss from all potential consequences and damages.

The Company's current insurance coverage includes (a) $400 million per occurrence from Oil Insurance Limited (OIL) for physical damage to Anadarko's properties on a replacement cost basis, blowout/control of well, restoration and redrill, and sudden and accidental pollution; (b) $1.2 billion per occurrence from the commercial markets for the items described in item (a) above, which is in excess of the OIL coverage and which follows the form of OIL coverage with certain exceptions; (c) $500 million from the commercial markets, which scales to Anadarko's working interest, for third-party liabilities, including sudden and accidental pollution and aviation liability; and (d) $275 million for aircraft liability (in addition to the third-party liability limits described in item (c) above). Anadarko does not carry significant coverage for loss of production income from any of the Company's facilities or for any losses that result from the effects of a named windstorm.

The Company's service agreements, including drilling contracts, generally indemnify Anadarko for injuries and death to employees of the service provider and subcontractors hired by the service provider as well as for property damage suffered by the service provider and its contractors. Also, these service agreements generally indemnify Anadarko for pollution originating from the equipment of any contractors or subcontractors hired by the service provider.

Off-Balance-Sheet Arrangements

Anadarko may enter into off-balance-sheet arrangements and transactions that can give rise to material off-balance-sheet obligations. The Company's material off-balance-sheet arrangements and transactions include operating lease arrangements and undrawn letters of credit. In addition, the Company enters into other contractual agreements in the normal course of business for processing, treating, transportation, and storage of oil, natural gas, and NGLs as well as for other oil and gas activities as discussed below in *Obligations*. Other than the items discussed above, there are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Anadarko's liquidity or availability of or requirements for capital resources.

Obligations

The following is a summary of the Company's obligations at December 31, 2017:

		Obligations by Period				
millions	Note Reference [(1)]	2018	2019-2020	2021-2022	2023 and Beyond	Total
Total debt						
Principal—total borrowings [(2)]	*Note 12*	$ 481	$ 1,298	$ 1,970	$ 13,283	$ 17,032
Interest on borrowings	*Note 12*	826	1,597	1,431	8,631	12,485
Capital lease obligation and interest	*Note 12*	53	85	84	365	587
Investee entities' debt and interest [(3)]	*Note 8*	82	183	191	2,073	2,529
Operating leases	*Note 16*	465	353	64	52	934
Oil and gas activities [(4)]	*Note 16*	408	280	101	127	916
Midstream and marketing activities	*Note 16*	859	1,757	1,260	1,310	5,186
AROs	*Note 14*	298	100	644	1,752	2,794
Derivative liabilities [(5)]	*Note 10*	344	486	397	183	1,410
Uncertain tax positions [(6)]	*Note 13*	21	53	72	1,171	1,317
Other [(7)]		37	192	58	84	371
Total [(8)]		$ 3,874	$ 6,384	$ 6,272	$ 29,031	$ 45,561

(1) For additional information, see the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) Includes the fully accreted principal amount of the Zero Coupons of approximately $2.4 billion as coming due after 2022. While the Zero Coupons do not mature until 2036, the outstanding Zero Coupons can be put to the Company each October, in whole or in part, for the then-accreted value. The Company could be required to repurchase the outstanding Zero Coupons at $930 million in October 2018 (the next potential put date).

(3) The obligations and related investments are presented net on the Company's Consolidated Balance Sheets in other assets or other long-term liabilities-other. Future interest payments are estimated using the relevant forward LIBOR rate curve. The preferred return that Anadarko receives on its investment in these entities is not included.

(4) Includes long-term drilling and work-related commitments of $916 million, comprised of approximately $815 million related to the United States and $101 million related to international locations. Amounts are undiscounted and do not include purchase commitments for jointly owned fields and facilities where the Company is not the operator.

(5) Represents Anadarko's gross derivative liability after taking into account the impacts of netting margin and collateral balances deposited with counterparties.

(6) Timing of conclusion of the uncertain tax positions cannot be determined with certainty.

(7) Includes environmental liabilities; for additional information, see *Note 17—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(8) Excludes litigation-related contingent liabilities, the Company's pension and postretirement benefit obligations, or payments related to the conveyance of future hard-minerals royalty revenues. See *Note 17—Contingencies*, *Note 19—Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans*, and *Note 15—Conveyance of Future Hard-Minerals Royalty Revenues* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of the Company's significant accounting policies. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment. The selection, development, and disclosure of these estimates is discussed with the Company's Audit Committee.

Proved Reserves

Methodology Anadarko estimates its proved oil and gas reserves according to the definition of proved reserves provided by the SEC and the FASB. This definition includes oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc. (at prices and costs as of the date the estimates are made). Prices include consideration of price changes provided only by contractual arrangements, and do not include adjustments based on expected future conditions. For reserves information, see *Oil and Gas Properties and Activities—Proved Reserves* under Items 1 and 2 of this Form 10-K and the *Supplemental Information on Oil and Gas Exploration and Production Activities* under Item 8 of this Form 10-K.

Judgments and uncertainties Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, development plans, reservoir performance, prices, economic conditions, and governmental restrictions as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date.

A material adverse change in the estimated volumes of proved reserves could have a negative impact on DD&A and could result in property or goodwill impairments. If the estimates of proved reserves used in the UOP calculations had been lower by 10% across all properties, DD&A in 2017 would have increased by approximately $405 million.

Exploratory Costs

Methodology Under the successful efforts method of accounting, exploratory drilling costs are initially capitalized pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned.

Judgments and uncertainties Significant management judgment is required to determine whether sufficient progress has been made in assessing the reserves and the economic and operating viability of the project to continue capitalization of the exploratory drilling costs. In making this determination all relevant facts and circumstances shall be evaluated, and no single indicator is determinative. Relevant facts and circumstances include, but are not limited to, commitment of project personnel, costs being incurred to assess the reserves and their potential development, assessment in progress covering the economic, legal, political, and environmental aspects of the potential development, and the existence or active negotiations of agreements with governments or sales contracts with customers. The determination of proved reserves may take longer than one year in certain areas (generally in deepwater and international locations) depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations.

If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. Therefore, at any point in time, the Company may have capitalized costs on its Consolidated Balance Sheets associated with exploratory wells that may be charged to exploration expense in future periods. See *Note 6—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Fair Value

Methodology The Company estimates fair value of long-lived assets for impairment testing, reporting units for goodwill impairment testing when necessary, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, pension plan assets, and initial measurements of AROs.

Judgments and uncertainties When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, the Company uses the cost or income approaches depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of future net cash flows and discounts the expected cash flows using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment, and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors and are consistent with assumptions used in the Company's business plans and investment decisions.

Impairments of Proved Oil and Natural-Gas Properties

Methodology Proved oil and natural-gas properties are assessed for impairment when facts and circumstances indicate that net book values may not be recoverable. When impairment indicators are present, an undiscounted future net cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, the property's fair value is estimated and an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value.

Judgments and uncertainties The primary assumptions used to estimate undiscounted future net cash flows include anticipated future production, commodity prices, and capital and operating costs. In most cases, the assumption that generates the most variability in undiscounted future net cash flows is future commodity prices. For impairment testing, the Company used the five-year forward strip prices for oil and natural gas, with prices subsequent to the fifth year held constant as the benchmark price in the undiscounted future net cash flows. Capital and operating costs were estimated assuming 1% escalation for the first five years and held constant thereafter.

Due to the volatility of crude oil, natural gas, and NGLs prices, these cash flow estimates are inherently imprecise. Unfavorable changes in any of the primary assumptions could result in a reduction in undiscounted future cash flows and could indicate property impairment. Uncertainties related to the primary assumptions could affect the timing of an impairment.

Impairments of Unproved Oil and Natural-Gas Properties

Methodology Acquisition costs of unproved oil and natural-gas properties are periodically assessed for impairment and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. The Company has classified unproved oil and natural-gas properties into three categories: significant, significant where probable and possible reserve estimations are available, and individually insignificant. Significant undeveloped leases are assessed individually for impairment and a valuation allowance is provided if impairment is indicated. In situations where fair values have been allocated to a significant unproved property based on estimations of probable and possible reserves as the result of a business combination or other purchase of proved and unproved properties, an undiscounted future net cash flow analysis is used to assess the property for impairment in addition to consideration of reserve volumes needed to transfer the balance of unproved property to proved property. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease terms at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment.

Judgments and uncertainties In determining whether a significant unproved property is impaired numerous factors are considered including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, geologists' evaluation of the property, and the remaining months in the lease term for the property. In situations where probable and possible reserves are available, undiscounted future net cash flows used in the impairment analysis are determined based upon management's estimates of probable and possible reserves, future commodity prices, and future costs to produce the reserves. If undiscounted future net cash flows are less than the carrying value of the property, indicating impairment, the future net cash flows are discounted and compared to the carrying value for determining the amount of the impairment loss to record. The Company utilizes the same pricing and cost assumptions discussed above in Impairments of Proved Oil and Natural-Gas Properties. Uncertainties related to the primary assumptions or unfavorable revisions in estimated reserve quantities could cause a reduction in the value of a property and therefore indicate an impairment. Management's assessment of the results of exploration activities, availability of funds for future activities, and the current and projected political and regulatory climate in areas in which the Company operates also impact the amounts and timing of impairment provisions.

Income Taxes

Methodology The Company is subject to income taxes in numerous taxing jurisdictions worldwide. The amount of income taxes recorded by the Company requires interpretations of complex rules and regulations of various tax jurisdictions throughout the world. The Company has recognized deferred tax assets and liabilities for temporary differences, operating losses, and tax-credit carryforwards.

The deferred tax assets may be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company routinely assesses the realizability of its deferred tax assets by analyzing the reversal periods of available net operating loss carryforwards and credit carryforwards, temporary differences in tax assets and liabilities, the availability of tax planning strategies, and estimates of future taxable income and other factors.

The Company also routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts, including interest where appropriate. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position.

Judgments and uncertainties The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. The assessment of potential uncertain tax positions requires a significant amount of judgment and are reviewed and adjusted on a periodic basis, taking into consideration the progress of ongoing tax audits, case law, and new legislation. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future based on the progress of ongoing tax audits, changes in legislation, and resolution of pending tax matters. Additionally, numerous judgments and assumptions are inherent in management's estimates of future taxable income used to assess the realizability of certain deferred tax assets. The estimates used are based on assumptions of proved oil and gas reserves, selling prices, and development assumptions that are consistent with the Company's internal business plans.

Goodwill Impairments

Methodology The Company tests goodwill for impairment annually in October (or more frequently as circumstances dictate). The Company first assesses whether an impairment of goodwill is indicated through a qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is less than its carrying amount, including goodwill. If the Company concludes it is more likely than not that fair value of the reporting unit exceeds the related carrying amount, then goodwill is not impaired and further testing is not necessary. If the qualitative assessment indicates fair value of the reporting unit may be less than its carrying amount, the Company compares the estimated fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets, including goodwill, and determines whether impairment is necessary.

When evaluating whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company assesses relevant events and circumstances, including the following:

- significant changes in the stock price of Anadarko, WES, and WGP
- significant declines in commodity prices
- significant increases in cost factors such as costs of drilling, production costs, and gathering, processing, and other transportation costs
- impairments recognized by the Company
- acquisitions and disposals of assets
- changes to the Company's reserves, including changes due to fluctuations in commodity prices and updates to the Company's plans or forecasts
- significant declines in trading multiples for midstream peers

Judgments and uncertainties The first step of the goodwill impairment test requires management to make estimates regarding the fair value of each reporting unit to which goodwill has been assigned. If it is necessary to determine the fair value of the reporting unit, a combination of the income approach and the market approach would be used. Because quoted market prices for the Company's reporting units are not available, management would apply judgment in determining the estimated fair value of reporting units for purposes of performing goodwill impairment tests, when such tests are necessary. Management would use information available to make these fair-value estimates, including the present values of expected future cash flows, using discount rates commensurate with the risks associated with the assets and the Exploration and Production reporting unit, control premiums and market multiples of earnings before interest, taxes, depreciation, and amortization (EBITDA) for the gathering and processing and transportation reporting units.

In estimating the fair value of its Exploration and Production reporting unit, an income approach to calculate the present value of expected future cash flows would be used, which would be based on forecasted assumptions. Key assumptions to the income approach would be similar to those described above regarding the impairment of long-lived assets, such as estimates of forecasted revenue and operating costs, proved reserves, the success of future exploration for and development of unproved reserves, discount rates, and other variables. Management would also include control premium assumptions based on observable market information regarding how a market participant would value the Exploration and Production reporting unit as a whole rather than as individual properties that are part of an oil and gas portfolio.

Management would estimate the fair value for the WES Gathering and Processing, WES Transportation, and Other Midstream reporting units by applying an estimated multiple to projected EBITDA. Management would consider observable transactions in the market and trading multiples for peers in determining an appropriate multiple to apply against the Company's projected EBITDA for these reporting units.

A lower fair-value estimate in the future for any of these reporting units could result in impairment of goodwill. Factors that could trigger a lower fair-value estimate include significant declines in commodity prices, decreases in proved reserves, changes in exploration or development plans, significant property impairments, increases in operating or drilling costs, significant changes in regulations, or other negative changes to the economic environment in which Anadarko operates.

Contingencies

Methodology The Company is subject to various legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses when such losses are probable and reasonably estimable. If the Company determines that a loss is probable and cannot estimate a specific amount for that loss, but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. The Company's in-house legal counsel personnel regularly assess contingent liabilities and, in certain circumstances, consult with third-party legal counsel or consultants to assist in the evaluation of the Company's liability for these contingencies.

Judgments and uncertainties Management makes judgments and estimates when it establishes liabilities for litigation and other contingent matters. Estimates of litigation-related liabilities are based on the facts and circumstances of the individual case and on information currently available to the Company. The extent of information available varies based on the status of the litigation and the Company's evaluation of the claim and legal arguments. In future periods, a number of factors could significantly change the Company's estimate of litigation-related liabilities, including discovery activities; briefings filed with the relevant court; rulings from the court made pre-trial, during trial, or at the conclusion of any trial; and similar cases involving other plaintiffs and defendants that may set or change legal precedent. As events unfold throughout the litigation process, the Company evaluates the available information and may consult with third-party legal counsel to determine whether liability accruals should be established or adjusted.

Purchase Price Allocations

Methodology In connection with a business combination accounted for under the acquisition method, the acquiring company must recognize and measure assets acquired and liabilities assumed at fair value as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of the purchase price over fair value assigned to assets and liabilities is recorded as goodwill. Any excess of fair value assigned to assets and liabilities over the purchase price is recorded as a gain from a bargain purchase. The amount of goodwill or gain from a bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

Judgments and uncertainties In estimating the fair values of assets acquired and liabilities assumed in a business combination, various assumptions are made. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, estimates of the fair value of crude oil, natural-gas and NGLs reserves are prepared. The Company utilizes the same pricing and cost assumptions discussed above in Impairments of Proved Oil and Natural-Gas Properties. For estimated proved reserves, the future net cash flows are discounted using a market-based discount rate determined appropriate at the time of the acquisition. Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Estimated fair values of assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

RECENT ACCOUNTING DEVELOPMENTS

See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of recent accounting developments affecting the Company.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. These risks can affect revenues and cash flows, and the Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments used by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Both exchange and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

COMMODITY-PRICE RISK The Company's most significant market risk relates to prices for oil, natural gas, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant decline. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 70 MMBbls of oil and 91 Bcf of natural gas at December 31, 2017, with a net derivative liability position of $161 million. Based on actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $380 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $327 million. However, any cash received or paid to settle these derivatives would be substantially offset by the sales value of production covered by the derivative instruments.

For additional information regarding the Company's marketing activities, see Items 1 and 2 of this Form 10-K.

INTEREST-RATE RISK Borrowings, if any, under each of the 364-Day Facility, the APC RCF, the WES RCF, and the WGP RCF are subject to variable interest rates. The balance of Anadarko's short-term and long-term debt on the Company's Consolidated Balance Sheets has fixed interest rates. The Company has $2.9 billion of LIBOR-based obligations that are presented on the Company's Consolidated Balance Sheets net of preferred investments in two noncontrolled entities. These obligations give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. While a 10% change in LIBOR would not materially impact the Company's interest cost, it would affect the fair value of outstanding fixed-rate debt.

At December 31, 2017, the Company had a net derivative liability position of $1.4 billion related to interest-rate swaps. A 10% increase (decrease) in the three-month LIBOR interest-rate curve would decrease (increase) the aggregate fair value of outstanding interest-rate swap agreements by $88 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by changes in actual borrowing costs associated with future debt issuances. For a summary of the Company's outstanding interest-rate derivative positions, see *Note 10—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Item 8. Financial Statements and Supplementary Data

ANADARKO PETROLEUM CORPORATION
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

ANADARKO PETROLEUM CORPORATION

REPORT OF MANAGEMENT

Management prepared, and is responsible for, the Consolidated Financial Statements and the other information appearing in this annual report. The Consolidated Financial Statements present fairly the Company's financial condition, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its Consolidated Financial Statements, the Company includes amounts that are based on estimates and judgments that Management believes are reasonable under the circumstances. The Company's financial statements have been audited by KPMG LLP, an independent registered public accounting firm appointed by the Audit Committee of the Board of Directors. Management has made available to KPMG LLP all of the Company's financial records and related data, as well as the minutes of the stockholders' and Directors' meetings.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Anadarko's internal control system was 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.

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.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2017. This assessment was based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. Based on our assessment, we believe that the Company's internal control over financial reporting was effective as of December 31, 2017.

KPMG LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2017.

/s/ R. A. WALKER

R. A. Walker
Chairman, President and Chief Executive Officer

/s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

February 15, 2018

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Anadarko Petroleum Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Anadarko Petroleum Corporation and subsidiaries' (the "Company") 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. 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 Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"), and our report dated February 15, 2018 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management – *Management's Assessment of Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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/ KPMG LLP

Houston, Texas
February 15, 2018

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
Anadarko Petroleum Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2017, and the related notes (collectively, the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), 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, and our report dated February 15, 2018 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 1981.

Houston, Texas
February 15, 2018

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
millions except per-share amounts	**2017**	2016	2015
Revenues and Other			
Oil sales	**$ 6,552**	$ 4,668	$ 5,420
Natural-gas sales	**1,348**	1,564	2,007
Natural-gas liquids sales	**1,069**	921	833
Gathering, processing, and marketing sales	**2,000**	1,294	1,226
Gains (losses) on divestitures and other, net	**939**	(578)	(788)
Total	**11,908**	7,869	8,698
Costs and Expenses			
Oil and gas operating	**1,000**	811	1,014
Oil and gas transportation	**914**	1,002	1,117
Exploration	**2,541**	946	2,644
Gathering, processing, and marketing	**1,560**	1,087	1,054
General and administrative	**1,075**	1,440	1,176
Depreciation, depletion, and amortization	**4,279**	4,301	4,603
Production, property, and other taxes	**582**	536	553
Impairments	**408**	227	5,075
Other operating expense	**221**	118	271
Total	**12,580**	10,468	17,507
Operating Income (Loss)	**(672)**	(2,599)	(8,809)
Other (Income) Expense			
Interest expense	**932**	890	825
Loss on early extinguishment of debt	**2**	155	—
(Gains) losses on derivatives, net	**135**	286	(99)
Other (income) expense, net	**(53)**	(101)	154
Total	**1,016**	1,230	880
Income (Loss) Before Income Taxes	**(1,688)**	(3,829)	(9,689)
Income tax expense (benefit)	**(1,477)**	(1,021)	(2,877)
Net Income (Loss)	**(211)**	(2,808)	(6,812)
Net income (loss) attributable to noncontrolling interests	**245**	263	(120)
Net Income (Loss) Attributable to Common Stockholders	**$ (456)**	$ (3,071)	$ (6,692)
Per Common Share			
Net income (loss) attributable to common stockholders—basic	**$ (0.85)**	$ (5.90)	$ (13.18)
Net income (loss) attributable to common stockholders—diluted	**$ (0.85)**	$ (5.90)	$ (13.18)
Average Number of Common Shares Outstanding—Basic	**548**	522	508
Average Number of Common Shares Outstanding—Diluted	**548**	522	508
Dividends (per Common Share)	**$ 0.20**	$ 0.20	$ 1.08

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
millions	**2017**	2016	2015
Net Income (Loss)	**$ (211)**	$ (2,808)	$ (6,812)
Other Comprehensive Income (Loss)			
Adjustments for derivative instruments			
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**3**	8	10
Income taxes on reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**(1)**	(3)	(4)
Total adjustments for derivative instruments, net of taxes	**2**	5	6
Adjustments for pension and other postretirement plans			
Net gain (loss) incurred during period	**(14)**	(175)	49
Income taxes on net gain (loss) incurred during period	**4**	68	(18)
Prior service credit (cost) incurred during period	**—**	—	89
Income taxes on prior service credit (cost) incurred during period	**—**	—	(33)
Amortization of net actuarial (gain) loss to general and administrative expense	**116**	188	63
Income taxes on amortization of net actuarial (gain) loss to general and administrative expense	**(40)**	(73)	(20)
Amortization of net prior service (credit) cost to general and administrative expense	**(25)**	(34)	(4)
Income taxes on amortization of net prior service (credit) cost to general and administrative expense	**10**	13	2
Total adjustments for pension and other postretirement plans, net of taxes	**51**	(13)	128
Total	**53**	(8)	134
Comprehensive Income (Loss)	**(158)**	(2,816)	(6,678)
Comprehensive income (loss) attributable to noncontrolling interests	**245**	263	(120)
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ (403)**	$ (3,079)	$ (6,558)

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

millions except per-share amounts	December 31, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents ($80 and $359 related to VIEs)	**$ 4,553**	$ 3,184
Accounts receivable (net of allowance of $14 and $14)		
Customers ($106 and $70 related to VIEs)	**1,222**	1,007
Others ($19 and $80 related to VIEs)	**607**	721
Other current assets	**380**	354
Total	**6,762**	5,266
Properties and Equipment		
Cost	**65,050**	69,013
Less accumulated depreciation, depletion, and amortization	**37,599**	36,845
Net properties and equipment ($5,731 and $5,050 related to VIEs)	**27,451**	32,168
Other Assets ($579 and $609 related to VIEs)	**2,211**	2,226
Goodwill and Other Intangible Assets ($1,191 and $1,221 related to VIEs)	**5,662**	5,904
Total Assets	**$ 42,086**	$ 45,564
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable		
Trade ($305 and $234 related to VIEs)	**$ 1,894**	$ 1,617
Other	**266**	303
Short-term debt - Anadarko [(1)]	**142**	42
Current asset retirement obligations	**294**	129
Other current liabilities	**1,310**	1,237
Total	**3,906**	3,328
Long-term Debt		
Long-term debt - Anadarko [(1)]	**12,054**	12,162
Long-term debt - WES and WGP	**3,493**	3,119
Total	**15,547**	15,281
Other Long-term Liabilities		
Deferred income taxes	**2,234**	4,324
Asset retirement obligations ($143 and $140 related to VIEs)	**2,500**	2,802
Other	**4,109**	4,332
Total	**8,843**	11,458
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 574.2 million and 572.0 million shares issued)	**57**	57
Paid-in capital	**12,000**	11,875
Retained earnings	**1,109**	1,704
Treasury stock (43.4 million and 20.8 million shares)	**(2,132)**	(1,033)
Accumulated other comprehensive income (loss)	**(338)**	(391)
Total Stockholders' Equity	**10,696**	12,212
Noncontrolling interests	**3,094**	3,285
Total Equity	**13,790**	15,497
Total Liabilities and Equity	**$ 42,086**	$ 45,564

Parenthetical references reflect amounts as of December 31, 2017, and December 31, 2016.

VIE amounts relate to WGP and WES. See *Note 24—Variable Interest Entities*.

(1) Excludes WES and WGP.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Total Stockholders' Equity						
millions	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2014	$ 52	$ 9,005	$ 12,125	$ (940)	$ (517)	$ 2,593	$ 22,318
Net income (loss)	—	—	(6,692)	—	—	(120)	(6,812)
Common stock issued	—	31	—	—	—	—	31
Share-based compensation expense	—	178	—	—	—	—	178
Dividends—common stock	—	—	(553)	—	—	—	(553)
Repurchase of common stock	—	—	—	(55)	—	—	(55)
Subsidiary equity transactions	—	51	—	—	—	99	150
Issuance of tangible equity units	—	—	—	—	—	348	348
Distributions to noncontrolling interest owners	—	—	—	—	—	(282)	(282)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	6	—	6
Adjustments for pension and other postretirement plans	—	—	—	—	128	—	128
Balance at December 31, 2015	52	9,265	4,880	(995)	(383)	2,638	15,457
Net income (loss)	—	—	(3,071)	—	—	263	(2,808)
Common stock issued	5	2,150	—	—	—	—	2,155
Share-based compensation expense	—	197	—	—	—	—	197
Dividends—common stock	—	—	(105)	—	—	—	(105)
Repurchase of common stock	—	—	—	(38)	—	—	(38)
Subsidiary equity transactions	—	263	—	—	—	746	1,009
Distributions to noncontrolling interest owners	—	—	—	—	—	(362)	(362)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	5	—	5
Adjustments for pension and other postretirement plans	—	—	—	—	(13)	—	(13)
Balance at December 31, 2016	**57**	**11,875**	**1,704**	**(1,033)**	**(391)**	**3,285**	**15,497**
Net income (loss)	**—**	**—**	**(456)**	**—**	**—**	**245**	**(211)**
Share-based compensation expense	**—**	**163**	**—**	**—**	**—**	**—**	**163**
Dividends—common stock	**—**	**—**	**(111)**	**—**	**—**	**—**	**(111)**
Repurchase of common stock	**—**	**—**	**—**	**(1,099)**	**—**	**—**	**(1,099)**
Subsidiary equity transactions	**—**	**(35)**	**—**	**—**	**—**	**9**	**(26)**
Distributions to noncontrolling interest owners	**—**	**—**	**—**	**—**	**—**	**(445)**	**(445)**
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**—**	**—**	**—**	**—**	**2**	**—**	**2**
Adjustments for pension and other postretirement plans	**—**	**—**	**—**	**—**	**51**	**—**	**51**
Cumulative effect of accounting change	**—**	**(3)**	**(28)**	**—**	**—**	**—**	**(31)**
Balance at December 31, 2017	**$ 57**	**$12,000**	**$ 1,109**	**$ (2,132)**	**$ (338)**	**$ 3,094**	**$ 13,790**

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

millions	Years Ended December 31, 2017	2016	2015
Cash Flows from Operating Activities			
Net income (loss)	**$ (211)**	$ (2,808)	$ (6,812)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Depreciation, depletion, and amortization	**4,279**	4,301	4,603
Deferred income taxes	**(2,169)**	(1,238)	(3,152)
Dry hole expense and impairments of unproved properties	**2,221**	613	2,267
Impairments	**408**	227	5,075
(Gains) losses on divestitures, net	**(674)**	757	1,022
Loss on early extinguishment of debt	**2**	155	—
Total (gains) losses on derivatives, net	**131**	292	(100)
Operating portion of net cash received (paid) in settlement of derivative instruments	**25**	267	335
Other	**303**	342	320
Changes in assets and liabilities			
Tronox-related contingent liability	**—**	—	(5,210)
(Increase) decrease in accounts receivable	**(147)**	677	(2)
Increase (decrease) in accounts payable and other current liabilities	**(32)**	(443)	(697)
Other items, net	**(127)**	(142)	474
Net cash provided by (used in) operating activities	**4,009**	3,000	(1,877)
Cash Flows from Investing Activities			
Additions to properties and equipment	**(5,031)**	(3,505)	(6,067)
Acquisition of businesses	**25**	(1,740)	(3)
Divestitures of properties and equipment and other assets	**4,008**	2,356	1,415
Other, net	**(30)**	127	(116)
Net cash provided by (used in) investing activities	**(1,028)**	(2,762)	(4,771)
Cash Flows from Financing Activities			
Borrowings, net of issuance costs	**369**	6,042	4,632
Repayments of debt	**(58)**	(6,832)	(4,033)
Financing portion of net cash received (paid) for derivative instruments	**(165)**	(333)	(35)
Increase (decrease) in outstanding checks	**(43)**	(103)	(23)
Dividends paid	**(111)**	(105)	(553)
Repurchase of common stock	**(1,092)**	(38)	(55)
Issuance of common stock	**—**	2,188	34
Sale of subsidiary units	**—**	1,163	187
Issuance of tangible equity units — equity component	**—**	—	348
Distributions to noncontrolling interest owners	**(445)**	(362)	(282)
Proceeds from conveyance of future hard-minerals royalty revenues, net of transaction costs	**—**	413	—
Payments of future hard-minerals royalty revenues conveyed	**(50)**	(25)	—
Other financing activities	**(18)**	—	—
Net cash provided by (used in) financing activities	**(1,613)**	2,008	220
Effect of Exchange Rate Changes on Cash	**1**	(1)	(2)
Net Increase (Decrease) in Cash and Cash Equivalents	**1,369**	2,245	(6,430)
Cash and Cash Equivalents at Beginning of Period	**3,184**	939	7,369
Cash and Cash Equivalents at End of Period	**$ 4,553**	$ 3,184	$ 939

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and sale of oil, natural gas, and NGLs and in advancing its Mozambique LNG project toward FID. In addition, the Company engages in the gathering, processing, treating, and transporting of oil, natural gas, and NGLs as well as gathering and disposal of produced water. The Company also participates in the hard-minerals business through royalty arrangements.

Basis of Presentation The consolidated financial statements have been prepared in conformity with GAAP. Certain prior-period amounts have been reclassified to conform to the current-year presentation.

During the second quarter of 2017, the Company revised its reporting segments to coincide with a change in how management reviews financial information and makes operating decisions. Also, beginning with year-end 2017, the Company will no longer aggregate the midstream operating segments and will present WES Midstream and Other Midstream as separate reporting segments in order to provide additional information useful to investors. The Company has reclassified prior period amounts to conform to the current period's presentation. See *Note 26—Segment Information* for additional information on the change in reporting segments.

The consolidated financial statements include the accounts of Anadarko and subsidiaries in which Anadarko holds, directly or indirectly, more than 50% of the voting rights and VIEs for which Anadarko is the primary beneficiary. The Company has determined that WGP and WES are VIEs. Anadarko is considered the primary beneficiary and consolidates WGP and WES. WGP and WES function with capital structures that are separate from Anadarko, consisting of their own debt instruments and publicly traded common units. All intercompany transactions have been eliminated. Undivided interests in oil and natural-gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in noncontrolled entities that Anadarko has the ability to exercise significant influence over operating and financial policies and VIEs for which Anadarko is not the primary beneficiary are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for the Company's proportionate share of earnings, losses, and distributions. Other investments are carried at original cost. Investments accounted for using the equity method and cost method are included in other assets.

Use of Estimates The preparation of financial statements in accordance with GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to proved reserves; the value of properties and equipment; goodwill; intangible assets; AROs; litigation liabilities; environmental liabilities; pension assets, liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

1. Summary of Significant Accounting Policies (Continued)

Fair Value Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1—Inputs represent unadjusted quoted prices in active markets for identical assets or liabilities (for example, exchange-traded futures contracts for which parties are willing to transact at the exchange-quoted price).

Level 2—Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3—Inputs that are not observable from objective sources such as the Company's internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company's internally developed present value of future cash flows model that underlies the fair-value measurement).

In determining fair value, the Company uses observable market data when available or models that incorporate observable market data. When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, the Company uses the cost or income approach depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of future net cash flows and discounts the expected cash flows using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment, and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors and are consistent with assumptions used in the Company's business plans and investment decisions.

In arriving at fair-value estimates, the Company uses relevant observable inputs available for the valuation technique employed. If a fair-value measurement reflects inputs at multiple levels within the hierarchy, the fair-value measurement is characterized based on the lowest level of input that is significant to the fair-value measurement. For Anadarko, recurring fair-value measurements are performed for interest-rate derivatives, commodity derivatives, and investments in trading securities.

The carrying amount of cash and cash equivalents, accounts receivable, and accounts payable reported on the Company's Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount the Company would have to pay to repurchase its debt, including any premium or discount attributable to the difference between the stated interest rate and market interest rate at each balance sheet date. Debt fair values, as disclosed in *Note 12—Debt and Interest Expense*, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments.

Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination or through a non-monetary exchange transaction, intangible assets, goodwill, AROs, exit or disposal costs, and capital lease assets and liabilities where the present value of lease payments is greater than the fair value of the leased asset.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

1. Summary of Significant Accounting Policies (Continued)

Revenues This section reflects the Company's revenue recognition policies through December 31, 2017. The Company adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, effective January 1, 2018. See Accounting Standards Adopted in 2018 below for further discussion.

The Company's oil is sold primarily to marketers, gatherers, and refiners. Natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies, and natural-gas marketers. NGLs are sold primarily to direct end-users, refiners, and marketers.

The Company recognizes sales revenues for oil, natural gas, and NGLs based on the amount of each product sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when product has been delivered to a pipeline or when a tanker lifting has occurred. The Company follows the sales method of accounting for natural-gas production imbalances. If the Company's sales volumes for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production.

Anadarko provides gathering, processing, treating, and transporting services pursuant to a variety of contracts. Under these arrangements, the Company receives fees or retains a percentage of products or a percentage of the proceeds from the sale of products and recognizes revenue at the time services are performed or product is sold. These revenues are included in gathering, processing, and marketing sales in the Company's Consolidated Statements of Income.

The Company enters into buy/sell arrangements related to the transportation of a portion of its oil production. Under these arrangements, barrels are sold to a third party at a location-based contract price and subsequently repurchased by the Company at a downstream location. The difference in value between the sale and purchase price represents the transportation fee from the lease or certain gathering locations to more liquid markets. These arrangements are often required by private transporters. These transactions are reported on a net basis and included in oil and gas transportation in the Company's Consolidated Statements of Income.

Cash Equivalents The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents. The cash equivalents balance at December 31, 2017, includes commercial paper and investments in government money market funds in which the carrying value approximates fair value.

Accounts Receivable and Allowance for Uncollectible Accounts The Company conducts credit analyses of customers prior to making any sales to new customers or increasing credit for existing customers. Based on these analyses, the Company may require a standby letter of credit or a financial guarantee. The Company charges uncollectible accounts receivable against the allowance for uncollectible accounts when it determines collection will no longer be pursued.

Inventories Commodity inventories are stated at the lower of average cost or market.

1. Summary of Significant Accounting Policies (Continued)

Properties and Equipment Properties and equipment are stated at cost less accumulated DD&A. Costs of improvements that extend the lives of existing properties are capitalized. Maintenance and repairs are expensed as incurred. Upon retirement or sale, the cost of properties and equipment, net of the related accumulated DD&A, is removed and, if appropriate, gain or loss is recognized in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income.

Oil and Gas Properties The Company applies the successful efforts method of accounting for oil and gas properties. Exploration costs, such as exploratory geological and geophysical costs, delay rentals, and exploration overhead, are charged against earnings as incurred. Exploratory drilling costs are initially capitalized pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed.

Acquisition costs of unproved properties are periodically assessed for impairment and are transferred to proved properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease terms at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged against the valuation allowance, while costs of productive leases are transferred to proved properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration expense in the Company's Consolidated Statements of Income.

Capitalized Interest For significant projects, interest is capitalized as part of the historical cost of developing and constructing assets. Significant oil and gas investments in unproved properties, significant exploration and development projects that have not commenced production, significant midstream development activities that are in progress, and investments in equity-method affiliates that are undergoing the construction of assets that have not commenced principle operations qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment. See *Note 12—Debt and Interest Expense*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

1. Summary of Significant Accounting Policies (Continued)

Asset Retirement Obligations AROs associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value and is included in DD&A in the Company's Consolidated Statements of Income. If estimated future costs of AROs change, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. See *Note 14—Asset Retirement Obligations*.

Impairments Properties and equipment are reviewed for impairment when facts and circumstances indicate that net book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value. See *Note 5—Impairments*.

Depreciation, Depletion, and Amortization Costs of drilling and equipping successful wells, costs to construct or acquire facilities other than offshore platforms, associated asset retirement costs, and capital lease assets used in oil and gas activities are depreciated using the UOP method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties and costs to construct or acquire offshore platforms and associated asset retirement costs, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves. Mineral properties are also depleted using the UOP method. All other properties are stated at historical acquisition cost, net of impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 40 years for buildings, and up to 43 years for gathering facilities.

Goodwill and Other Intangible Assets Anadarko has allocated goodwill to the following reporting units: Exploration and Production; WES Gathering and Processing; WES Transportation; and Other Midstream. Goodwill is subject to annual impairment testing in October (or more frequent testing as circumstances dictate). Anadarko's goodwill impairment test first assesses qualitative factors to determine whether goodwill is impaired. If the qualitative assessment indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount including goodwill, the Company will then perform a quantitative goodwill impairment test. Changes in goodwill may result from, among other things, impairments, acquisitions, or divestitures. See *Note 7—Goodwill and Other Intangible Assets*.

Other intangible assets represent contractual rights obtained in connection with business combinations that had favorable contractual terms relative to market at the acquisition date as well as customer-related intangible assets, including customer relationships established by acquired contracts. Other intangible assets are amortized over their estimated useful lives and are assessed for impairment with the associated long-lived asset group whenever impairment indicators are present. See *Note 7—Goodwill and Other Intangible Assets*.

1. Summary of Significant Accounting Policies (Continued)

Derivative Instruments Anadarko uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Derivatives are carried on the balance sheet at fair value and are included in other current assets, other assets, other current liabilities, or other long-term liabilities, depending on the derivative position and the expected timing of settlement, unless they satisfy the normal purchases and sales exception criteria. Where the Company has the contractual right and intends to net settle, derivative assets and liabilities are reported on a net basis.

Gains and losses on derivative instruments are recognized currently in earnings. Net losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and will be reclassified to earnings in future periods as the economic transactions to which the derivatives relate affect earnings. See *Note 10—Derivative Instruments*.

Legal Contingencies The Company is subject to legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for legal contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with legal claims when such losses are probable and reasonably estimable. If the Company determines that a loss is probable and cannot estimate a specific amount for that loss but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred. See *Note 17—Contingencies*.

Environmental Contingencies The Company is subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. Except for environmental contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with environmental obligations when such losses are probable and reasonably estimable. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable. See *Note 17—Contingencies*.

Noncontrolling Interests Noncontrolling interests represent third-party ownership in the net assets of the Company's consolidated subsidiaries and are presented as a component of equity. Changes in Anadarko's ownership interests in subsidiaries that do not result in deconsolidation are recognized in equity. See *Note 23—Noncontrolling Interests*.

Income Taxes The Company files various U.S. federal, state, and foreign income tax returns. The impact of changes in tax regulations are reflected when enacted. Deferred federal, state, and foreign income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority. Interest and penalties related to unrecognized tax benefits are recognized in income tax expense (benefit). The Company uses the flow-through method to account for its investment tax credits. See *Note 13—Income Taxes*.

1. Summary of Significant Accounting Policies (Continued)

Share-Based Compensation The Company accounts for share-based compensation at fair value. The Company grants equity-classified awards, including stock options and non-vested equity shares (restricted stock awards and units). The Company may also grant equity-classified and liability-classified awards based on a comparison of the Company's TSR to the TSR of a predetermined group of peer companies (performance units).

The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of Anadarko common stock. For other share-based compensation awards, fair value is determined using a Monte Carlo simulation.

The Company records compensation cost, net of actual forfeitures, for share-based compensation awards over the requisite service period using the straight-line method. For equity-classified share-based compensation awards, expense is recognized based on the grant-date fair value. For liability-classified share-based compensation awards, expense is recognized for those awards expected to ultimately be paid. The amount of expense reported for liability-classified awards is adjusted for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See *Note 22—Share-Based Compensation*.

Accounting Standards Adopted in 2017 ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)*, eliminates Step 2 from the goodwill impairment test in an effort to simplify the subsequent measurement of goodwill. The Company adopted this ASU using a prospective approach on January 1, 2017. This ASU will only be applicable to the extent that the Company determines its goodwill is impaired.

ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*, assists in determining whether a transaction should be accounted for as an acquisition or disposal of assets or as a business. This ASU provides a screen that when substantially all of the fair value of the gross assets acquired, or disposed of, are concentrated in a single identifiable asset, or a group of similar identifiable assets, the set will not be considered a business. If the screen is not met, the assets must include an input and a substantive process that together significantly contribute to the ability to create an output to be considered a business. The Company's adoption of this ASU on January 1, 2017, using a prospective approach, could have a material impact on future consolidated financial statements as goodwill will not be allocated to divestitures or recorded on acquisitions that are not considered businesses. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale*.

ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory*, requires an entity to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs and eliminates the exception for an intra-entity transfer of an asset other than inventory. The Company adopted this ASU on January 1, 2017, using a modified retrospective approach, and recognized a cumulative adjustment to retained earnings of $31 million during the first quarter of 2017.

ASU 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*, simplifies the accounting for share-based payment transactions, including the income tax consequences, classification on the statement of cash flows, accounting for forfeitures, and classification of awards as either equity or liabilities. Beginning on January 1, 2017, excess tax benefits and tax deficiencies related to share-based compensation are reflected on a prospective basis in the income statement as a component of the provision for income taxes rather than additional paid-in capital as previously recognized. For the year ended December 31, 2017, the Company recognized a $19 million tax deficiency as an increase to the provision for income taxes. Cash flows related to excess tax benefits are classified on a prospective basis as operating activities in the statement of cash flows rather than cash inflows from financing activities and cash outflows from operating activities as previously recognized. Prior periods of the statement of cash flows were not adjusted as there was no material impact. In addition, the Company began accounting for share-based compensation award forfeitures when they occur instead of estimating the number of forfeitures expected, with this change in accounting not having a material impact on the Company's consolidated financial statements.

1. Summary of Significant Accounting Policies (Continued)

Accounting Standards Adopted in 2018 ASU 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, requires presentation of service cost in the same line item(s) as other compensation costs arising from services rendered by employees during the period and presentation of the remaining components of net benefit cost in a separate line item outside operating items. Additionally, only the service cost component of net benefit cost will be eligible for capitalization. The Company adopted this ASU on January 1, 2018, with retrospective presentation of the service cost component and the other components of net benefit cost in the income statement and prospective presentation for the capitalization of the service cost component of net benefit cost in assets. Upon adoption, non-service cost components of net periodic benefit costs of $107 million for the year ended December 31, 2017, and $225 million for the year ended December 31, 2016, will be reclassified to other (income) expense, net, from G&A; oil and gas operating; gathering, processing, and marketing; and exploration expense. The Company does not expect any other significant changes upon adoption of this ASU.

ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash*, 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 of the totals in that statement to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. The Company adopted this ASU using a retrospective approach on January 1, 2018. Adoption will not have a material impact on the Company's consolidated financial statements.

ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, supersedes current revenue recognition requirements and industry-specific guidance and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company adopted this new standard on January 1, 2018, using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. The cumulative effect adjustment that will be recognized in the opening balance of retained earnings will not be material. The Company has implemented the necessary changes to its business processes, systems, and controls to support recognition and disclosure of this ASU upon adoption on January 1, 2018. Beginning in 2018, additional quantitative and qualitative disclosures will be required, including expanded descriptions of the nature, amount, timing, and uncertainty of revenue and cash flows from contracts with customers as well as details of related contract assets and liabilities. This ASU also requires disclosures about revenue from customers on a disaggregated basis. While the Company does not expect 2018 net earnings to be materially impacted by revenue recognition timing changes as a result of the application of this ASU, there will be certain changes to the presentation of revenues and related expenses beginning January 1, 2018. The impact of adopting this ASU includes the following:

- **Exploration and Production**—No significant impact is expected for the recognition, measurement, or presentation of oil, natural-gas, or NGLs sales revenues.
- **WES Midstream and Other Midstream**—Gathering and processing revenues will decrease for contracts where the Company is acting as an agent for its processing customer in the sale of processed volumes and increase for contracts with noncash consideration that will generally be valued at current market prices of the commodity received, with an offset in gathering and processing expense. The magnitude of these changes is dependent on future customer volumes subject to the impacted contracts and commodity prices for those volumes. While reported gathering and processing revenues and expenses will be materially reduced, these presentation changes will not impact net earnings.

1. Summary of Significant Accounting Policies (Continued)

New Accounting Standards Issued But Not Yet Adopted ASU 2016-02, *Leases (Topic 842),* requires lessees to recognize a lease liability and a right-of-use (ROU) asset for all leases, including operating leases, with a term greater than 12 months on the balance sheet. This ASU modifies the definition of a lease and outlines the recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. Certain practical expedients will be used to implement the new standard, and the Company will not reassess contracts that commenced prior to adoption. The Company will make a policy election not to recognize ROU assets or lease liabilities for leases with a term of 12 months or less. Anadarko is reviewing contracts for its portfolio of leased assets to assess the impact of adopting the new standard, which is expected to primarily affect other assets and other long-term liabilities. The Company is also evaluating its systems, processes, and internal controls to facilitate compliance with the new standard. The Company will complete its evaluation in 2018 and adopt this new standard on January 1, 2019, using a modified retrospective approach for all comparative periods presented.

2. Inventories

The following summarizes the major classes of inventories included in other current assets at December 31:

millions	**2017**	2016
Oil	**$ 165**	$ 169
Natural gas	**29**	38
NGLs	**122**	106
Total inventories	**$ 316**	$ 313

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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3. Acquisitions, Divestitures, and Assets Held for Sale

Acquisitions On December 15, 2016, the Company closed the GOM Acquisition for $1.8 billion using a portion of the net proceeds from the September 2016 issuance of 40.5 million shares of its common stock. This acquisition constitutes a business combination and was accounted for using the acquisition method of accounting. This acquisition expanded Anadarko's operated infrastructure and tie-back inventory, more than doubled the Company's ownership in the Lucius development to approximately 49%, and doubled its net production from the Gulf of Mexico. The following summarizes the fair value of assets acquired and liabilities assumed at the acquisition date, which were finalized during the quarter ended June 30, 2017:

millions		
Current assets	$	8
Properties and equipment		2,492
Other assets		145
AROs		(816)
Net assets acquired	$	1,829
Accounts payable		(5)
Other long-term liabilities		(109)
Cash paid	$	1,715

Fair-value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. The fair value of properties and equipment is primarily based on income and cost approaches. As part of the acquisition, Anadarko agreed to pay the seller, on a quarterly basis, a proportionate amount of gross proceeds from a certain contract until the amount paid equals approximately $150 million. The fair value of the contingent consideration of $103 million was estimated using the income approach and is included in accounts payable and other long-term liabilities in the table above. The assets acquired and liabilities assumed are included within the Exploration and Production reporting segment. Results of operations attributable to the acquisition are included in the Company's Consolidated Statements of Income from the acquisition date and are not material to the Company's Consolidated Statements of Income.

The following summarizes the unaudited pro forma condensed financial information of the Company as if the acquisition had occurred on January 1, 2015:

millions		**2016**		**2015**
Revenues	$	8,849	$	9,786
Net income (loss)		(2,623)		(6,560)

The unaudited pro forma information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the acquisition been completed at January 1, 2015, nor is it necessarily indicative of future operating results of the combined entity. The pro forma information includes adjustments for revenues and direct expenses based on historical results of the acquired assets and DD&A based on the purchase price allocated to property, plant, and equipment and estimated useful lives. Adjustments are not included for the acquired assets' historical property impairments as they were made under the full cost method of accounting. The pro forma adjustments include estimates and assumptions based on currently available information. Management believes the estimates and assumptions are reasonable, and the relative effects of the transaction are properly reflected. The unaudited pro forma information does not reflect any cost savings anticipated as a result of the acquisition or any future acquisition related expenses.

3. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

Property Exchange On March 17, 2017, WES acquired a third party's 50% nonoperated interest in the DBJV System in exchange for WES's 33.75% interest in nonoperated Marcellus midstream assets and $155 million in cash. WES recognized a gain of $126 million as a result of this transaction. After the acquisition, the DBJV System is 100% owned by WES and consolidated by Anadarko.

Divestitures and Assets Held for Sale The following summarizes the proceeds received and gains (losses) recognized on divestitures and assets held for sale for the years ended December 31:

millions	**2017**	2016	2015
Proceeds received, net of closing adjustments	**$ 4,008**	$ 2,356	$ 1,415
Gains (losses) on divestitures, net [(1)] [(2)]	**674**	(757)	(1,022)

(1) Includes goodwill allocated to divestitures of $209 million in 2017, $397 million in 2016, and $184 million in 2015.
(2) Includes the $126 million gain related to the property exchange discussed above.

2017 During the year ended December 31, 2017, the Company divested of the following assets:

- Eagleford assets in South Texas, included in the Exploration and Production reporting segment, for net proceeds of $2.1 billion and a net gain of $729 million
- Eaglebine assets in Southeast Texas, included in the Exploration and Production reporting segment, for net proceeds of $533 million and a net gain of $282 million
- CBM assets in Utah, included in the Exploration and Production and WES Midstream reporting segments, for net proceeds of $69 million and a net loss of $52 million
- Marcellus assets in Pennsylvania, included in the Exploration and Production and Other Midstream reporting segments, for net proceeds of $951 million and net losses of $55 million in 2017 and $129 million in 2016
- Moxa assets in Wyoming, included in the Exploration and Production reporting segment, for net proceeds of $313 million and a net loss of $204 million

Certain nonoperated assets located in Alaska included in the Exploration and Production reporting segment satisfied criteria to be considered held for sale during the fourth quarter of 2017, at which time the Company remeasured these assets to their current fair value using a market approach and Level 2 fair-value measurement and recognized a loss of $154 million. At December 31, 2017, the Company's Consolidated Balance Sheet included long-term assets of $573 million and long-term liabilities of $27 million associated with assets held for sale. Subsequent to year end, the Company divested its nonoperated interest in Alaska for net proceeds of $383 million. The transaction is subject to regulatory approval.

3. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

2016 During the year ended December 31, 2016, the Company divested of the following assets:

- Hugoton assets in Kansas, included in the Exploration and Production and WES Midstream reporting segments, for net proceeds of $159 million and a loss of $4 million
- Ozona and Steward assets in West Texas, included in the Exploration and Production and Other Midstream reporting segments, for net proceeds of $221 million and a loss of $52 million
- Wamsutter assets in Wyoming, included in the Exploration and Production reporting segment, for net proceeds of $588 million and a loss of $58 million
- Elm Grove assets in East Texas, included in the Exploration and Production reporting segment, for net proceeds of $89 million and a loss of $64 million
- East Chalk and Carthage assets in East Texas/Louisiana, included in the Exploration and Production and Other Midstream reporting segments, for net proceeds of $1.0 billion and a net loss of $439 million

Certain Marcellus U.S. onshore assets located in Pennsylvania included in the Exploration and Production and Other Midstream reporting segments satisfied criteria to be considered held for sale during the fourth quarter of 2016, at which time the Company remeasured these assets to their current fair value using a market approach and Level 2 fair-value measurement and recognized a loss of $129 million. At December 31, 2016, the Company's Consolidated Balance Sheet included long-term assets of $1.2 billion, which included $193 million of goodwill, and long-term liabilities of $66 million associated with assets held for sale.

2015 During the year ended December 31, 2015, the Company divested of the following assets:

- Freestone and Dew Pinnacle assets in East Texas, included in the Exploration and Production and WES Midstream reporting segments, for net proceeds of $425 million and a loss of $110 million
- EOR assets in Wyoming, included in the Exploration and Production reporting segment, for net proceeds of $675 million and a loss of $350 million
- Powder River Basin CBM assets in Wyoming, included in the Exploration and Production and Other Midstream reporting segments, for net proceeds of $154 million and a loss of $538 million

4. Properties and Equipment

The following summarizes properties and equipment at December 31:

millions	**2017**	2016
Exploration and Production [(1)]	**$ 52,364**	$ 57,581
WES Midstream	**7,871**	6,862
Other Midstream	**2,012**	1,785
Other	**2,803**	2,785
Gross properties and equipment	**$ 65,050**	$ 69,013
Less accumulated DD&A	**37,599**	36,845
Net properties and equipment	**$ 27,451**	$ 32,168

(1) Includes costs associated with unproved properties of $2.4 billion at December 31, 2017, and $4.1 billion at December 31, 2016.

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5. Impairments

Impairments of Long-Lived Assets Impairments of long-lived assets are included in impairment expense in the Company's Consolidated Statements of Income. The following summarizes impairments of long-lived assets and the related post-impairment fair values by segment at December 31:

	2017		2016		2015	
millions	**Impairment**	**Fair Value [1]**	Impairment	Fair Value [1]	Impairment	Fair Value [1]
Exploration and Production						
U.S. onshore properties	**$ 2**	**$ 3**	$ 28	$ 617	$ 3,684	$ 1,253
Gulf of Mexico properties	**227**	**216**	27	61	349	65
Cost-method investment [2]	**—**	**—**	59	—	3	59
WES Midstream	**176**	**58**	16	3	515	36
Other Midstream	**2**	**—**	57	29	524	176
Other	**1**	**—**	40	—	—	—
Total impairments	**$ 408**	**$ 277**	$ 227	$ 710	$ 5,075	$ 1,589

(1) Measured as of the impairment date using the income approach and Level 3 inputs. The primary assumptions used to estimate undiscounted future net cash flows include anticipated future production, commodity prices, and capital and operating costs.

(2) The after-tax net investment fair value was $32 million at December 31, 2015.

2017 Impairments were primarily related to oil and gas properties in the Gulf of Mexico due to lower forecasted commodity prices and a U.S. onshore midstream property due to a reduced throughput fee as a result of a producer's bankruptcy.

2016 Impairments were primarily related to the uncertain recovery of the Company's Venezuelan cost-method investment, negative developments related to commercial negotiations of a certain midstream asset, impairment of an office building, changes in development plans for certain U.S. onshore oil and gas assets, and a reduction in estimated future cash flows related to an oil and gas property in the Gulf of Mexico.

2015 Impairments were primarily related to the Company's Greater Natural Buttes oil and gas and midstream properties, certain other U.S. onshore oil and gas and midstream properties, and oil and gas properties in the Gulf of Mexico, all of which were impaired due to lower forecasted commodity prices.

5. Impairments (Continued)

Impairments of Unproved Properties Impairments of unproved properties are included in exploration expense in the Company's Consolidated Statements of Income.

2017 The Company recognized $610 million of impairments of unproved Gulf of Mexico properties primarily due to an impairment of $463 million to the Shenandoah project. The unproved property balance related to the Shenandoah project originated from the purchase price allocated to Gulf of Mexico exploration projects from the acquisition of Kerr-McGee Corporation in 2006. The Company also recognized $88 million of impairments of unproved international properties. See *Note 6—Suspended Exploratory Well Costs*.

2016 The Company recognized a $72 million impairment of unproved properties in the Gulf of Mexico and $92 million of unproved international properties primarily in Brazil and Tunisia due to the Company's intentions to not pursue future exploration activities.

2015 The Company recognized a $935 million impairment of unproved Greater Natural Buttes properties and a $66 million impairment of an unproved Gulf of Mexico property as a result of lower commodity prices. Also in 2015, the Company recognized a $109 million impairment of unproved Utica properties resulting from an assignment of mineral interests in settlement of a legal matter.

It is reasonably possible that significant declines in commodity prices, further changes to the Company's drilling plans in response to lower prices, reduction of proved and probable reserve estimates, or increases in drilling or operating costs could result in other additional impairments.

6. Suspended Exploratory Well Costs

The following summarizes the changes in suspended exploratory well costs at December 31 for each of the last three years. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year:

millions	**2017**	2016	2015
Balance at January 1	**$ 1,230**	$ 1,124	$ 1,522
Additions pending the determination of proved reserves	**349**	490	461
Divestitures and other	**(36)**	(11)	(33)
Reclassifications to proved properties	**(41)**	(50)	(104)
Charges to exploration expense	**(977)**	(323)	(722)
Balance at December 31	**$ 525**	$ 1,230	$ 1,124

2017 During the year ended December 31, 2017, exploratory well costs charged to exploration expense primarily related to the following:

Gulf of Mexico

- *Shenandoah* The Company expensed $437 million of exploratory well costs, including $326 million of costs that were suspended as of December 31, 2016. The Shenandoah-6 appraisal well and subsequent sidetrack, which completed appraisal activities in April 2017 and did not encounter oil in the eastern portion of the field. Given the results of this well and the commodity-price environment, the Company suspended further appraisal activities.
- *Phobos* The Company expensed $215 million of exploratory well costs, including $99 million of costs that were suspended as of December 31, 2016, in the third quarter of 2017 related to wells at the Phobos project. These wells found insufficient quantities of oil pay to justify development in the current price environment.
- *Warrior* The Company expensed $108 million of exploratory well costs in the third quarter of 2017 related to the northern appraisal well and sidetrack at the Warrior project. These wells found insufficient quantities of oil pay to justify development of the northern portion of the field in the current price environment. Evaluation of tie-back opportunities in the southern portion of the field is ongoing.

Colombia

- The Company expensed $243 million of exploratory well costs, including $102 million of costs that were suspended as of December 31, 2016, related to wells in the Grand Fuerte area in Colombia due to insufficient progress on contractual and fiscal reforms needed for deepwater gas development. All remaining leases are contractually in good standing.

Côte d'Ivoire

- The Company expensed $329 million of exploratory well costs, including $237 million of costs that were suspended as of December 31, 2016, in Côte d'Ivoire. During 2017, the Company had unsuccessful drilling activities in the south channel of the Paon prospect and in Block CI-527 and after further evaluation of the well results, Anadarko withdrew from all Côte d'Ivoire blocks.

6. Suspended Exploratory Well Costs (Continued)

2016 During the year ended December 31, 2016, suspended exploratory well costs charged to exploration expense primarily related to the following:

Gulf of Mexico

- The Company expensed $231 million of suspended exploratory well costs in the Gulf of Mexico primarily related to the Yeti project, as the Company did not expect to have exploration activities on this prospect in the foreseeable future, and a Shenandoah well that was expensed, as it was no longer reasonably possible that the wellbore could be used in the development of the project.

Mozambique

- The Company expensed $92 million of suspended exploratory well costs in Mozambique. The Tubarão-Tigre discovery wells were expensed based on the outlook for development viability, the commodity market conditions, and the complexity introduced by the depth and characteristics of the reservoir. The Orca-4 well was expensed after additional reservoir analysis and the determination that the well was not associated with the first three Orca wells.

2015 During the year ended December 31, 2015, the Company expensed $565 million of suspended exploratory well costs in Brazil. The Company no longer expected to have substantive exploration and development activities in Brazil.

The following provides an aging of suspended well balances at December 31:

millions	**2017**	2016	2015
Exploratory well costs capitalized for a period of one year or less	**$ 201**	$ 460	$ 452
Exploratory well costs capitalized for a period greater than one year	**324**	770	672
Balance at December 31	**$ 525**	$ 1,230	$ 1,124

6. Suspended Exploratory Well Costs (Continued)

The following summarizes a further aging by geographic area of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling at December 31, 2017:

millions except projects	Number of Projects	Total	2016	2015	2014 and prior
U.S. Onshore	9	$ 44	$ 10	$ 4	$ 30
U.S. Offshore	1	74	74	—	—
International	3	206	14	87	105
	13	$ 324	$ 98	$ 91	$ 135

For exploratory wells, drilling costs are capitalized, or "suspended," on the balance sheet when the well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. Suspended exploratory well costs capitalized for a period greater than one year after completion of drilling at December 31, 2017, primarily related to the Gulf of Mexico, Ghana, and Mozambique.

Gulf of Mexico Exploratory well costs are primarily related to the Warrior and Calpurnia discoveries and have been suspended pending further appraisal activities for potential tieback to the existing infrastructure, including analysis of well results and geologic and geophysical studies, and project sanctioning.

Ghana Exploratory well costs are related to the Mahogany East and Teak prospects, which are included in the Greater Jubilee Full Field Development Plan approved by the Ghanaian government in October 2017. Well costs remain suspended pending further technical analysis and future drilling results.

Mozambique Exploratory well costs are primarily related to the Golfinho/Atum discovery and have been suspended pending FID. In 2017, Anadarko, its Area 1 co-venturers, and the Government of Mozambique completed the foundational legal and contractual framework required to support investment in the Company's onshore LNG project. Based on these project advances and the approved Resettlement Plan, the Company commenced resettlement activities during the fourth quarter of 2017. In 2017, the Company reached agreement on the project's first long-term sales and purchase agreement, subject to the approval of the Government of Thailand, and continues to progress additional LNG long-term sales contracts and advance the project finance process. The Development Plan for the initial two-train Golfinho/Atum project is in the final stages of the Government of Mozambique's approval process.

If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time.

7. Goodwill and Other Intangible Assets

Goodwill At December 31, 2017, the Company had $4.8 billion of goodwill allocated to the following reporting units: $4.3 billion to Exploration and Production, $411 million to WES Gathering and Processing, $5 million to WES Transportation, and $30 million to Other Midstream. During 2017, goodwill decreased $211 million primarily related to asset divestitures. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale*. The Company's 2017 annual qualitative impairment assessment of goodwill indicated no impairment.

Other Intangible Assets Intangible assets and associated amortization expense were as follows at December 31:

millions	**2017**	2016
Gross carrying amount	**$ 1,013**	$ 1,013
Accumulated amortization	**(140)**	(109)
Net carrying amount	**$ 873**	$ 904
Amortization expense	**$ 31**	$ 32

Intangible assets are primarily related to customer contracts associated with WES's 2014 acquisition of Delaware Basin Midstream, LLC. These contracts are being amortized over 30 years. The annual aggregate amortization expense for intangible assets is expected to be $31 million each of the next five years.

8. Equity-Method Investments

In 2007, Anadarko contributed certain of its oil and gas properties and gathering and processing assets, with an aggregate fair value of $2.9 billion at the time of the contribution, to newly formed unconsolidated entities in exchange for noncontrolling mandatorily redeemable LIBOR-based preferred interests in those entities. The common equity of the investee entities is 95% owned by third parties that also maintain control over the assets. Subsequent to their formation, the investee entities loaned Anadarko an aggregate of $2.9 billion, each with a 35-year term. The Company accounts for its investment in these entities using the equity method of accounting. The carrying amount of these investments was $2.8 billion and the carrying amount of notes payable to affiliates was $2.9 billion at December 31, 2017. Anadarko's noncontrolling interest may be redeemed beginning in 2022 by Anadarko or the owner of the controlling interest. Anadarko's interest is mandatorily redeemable in 2037. Anadarko has legal right of setoff and intends to net settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investment for each entity and the related obligation are presented net on the Company's Consolidated Balance Sheets. Other long-term liabilities—other included $46 million at December 31, 2017, and $48 million at December 31, 2016, and other assets included $4 million at December 31, 2017 and $2 million at December 31, 2016, related to these investments.

Interest on the notes issued by Anadarko is variable, and is equivalent to LIBOR plus a spread that fluctuates with Anadarko's credit rating. The applicable interest rate was 2.59% at December 31, 2017, and 1.96% at December 31, 2016. The note payable agreement contains a quarterly covenant that provides for a maximum Anadarko debt-to-capital ratio of 67% (excluding the effect of non-cash write-downs). Anadarko was in compliance with this covenant at December 31, 2017. Other (income) expense, net includes interest expense on the notes payable of $64 million in 2017, $49 million in 2016, and $37 million in 2015, and equity (earnings) losses from Anadarko's investments in the investee entities of $(56) million in 2017, $(33) million in 2016, and $15 million in 2015.

9. Current Liabilities

Accounts Payable Accounts payable, trade included liabilities of $219 million at December 31, 2017, and $262 million at December 31, 2016, representing the amount by which checks issued but not presented to the Company's banks for collection exceeded balances in applicable bank accounts. Changes in these liabilities are classified as cash flows from financing activities.

Other Current Liabilities The following summarizes the Company's other current liabilities:

millions	**December 31, 2017**	December 31, 2016
Accrued income taxes	**$ 71**	$ 6
Interest payable	**246**	244
Production, property, and other taxes payable	**216**	239
Accrued employee benefits	**210**	355
Derivatives	**384**	175
Other	**183**	218
Total other current liabilities	**$ 1,310**	$ 1,237

10. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations such as Cushing, Oklahoma or Sullom Voe, Scotland for oil and Henry Hub, Louisiana for natural gas. Basis swaps are periodically used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities (Marketing and Trading Derivative Activities).

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio is subject to changes in interest rates.

The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings. See *Note 21—Accumulated Other Comprehensive Income (Loss)*.

10. Derivative Instruments (Continued)

Oil and Natural-Gas Production/Processing Derivative Activities The oil prices listed below are a combination of NYMEX WTI and Intercontinental Exchange, Inc. (ICE) Brent Blend prices. The natural-gas prices listed below are NYMEX Henry Hub prices. The following is a summary of the Company's derivative instruments related to oil and natural-gas production/processing derivative activities at December 31, 2017:

	2018 Settlement	
Oil		
Two-Way Collars (MBbls/d)		108
Average price per barrel		
Ceiling sold price (call)	$	60.48
Floor purchased price (put)	$	50.00
Fixed-Price Contracts (MBbls/d)		84
Average price per barrel	$	61.45
Natural Gas		
Three-Way Collars (thousand MMBtu/d)		250
Average price per MMBtu		
Ceiling sold price (call)	$	3.54
Floor purchased price (put)	$	2.75
Floor sold price (put)	$	2.00

A two-way collar is a combination of two options: a sold call and a purchased put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes.

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

In January 2018, the Company entered into additional natural-gas fixed-price swaps consisting of 280 MMBtu/d at an average price of $3.02.

Marketing and Trading Derivative Activities The Company had financial derivative transactions with notional volumes of natural gas totaling 17 Bcf at December 31, 2017, and 2 Bcf at December 31, 2016, that were entered into to mitigate commodity-price risk related to fixed-price purchase and sales contracts and storage activity.

10. Derivative Instruments (Continued)

Interest-Rate Derivatives Anadarko has outstanding interest-rate swap contracts to manage interest-rate risk associated with anticipated debt issuances. The Company has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR.

In February 2016, in exchange for amended terms with certain counterparties, the Company modified the mandatory termination dates from 2021 to 2018 and, in some cases, the related fixed interest rates on interest-rate swaps with an aggregate notional principal amount of $500 million.

In June and July 2017, the Company amended certain interest-rate swaps with an aggregate notional principal amount of $750 million, extending the mandatory termination dates from 2018 to 2020, 2022, and 2023 in exchange for cash payments of approximately $72 million.

At December 31, 2017, the Company had outstanding interest-rate swaps with a notional amount of $1.6 billion due prior to or in September 2023 that manage interest-rate risk associated with the potential refinancing of the Company's future debt maturities. Depending on market conditions, liability-management actions, or other factors, the Company may enter into offsetting interest-rate swap positions or settle or amend certain or all of the currently outstanding interest-rate swaps. The Company had the following outstanding interest-rate swaps at December 31, 2017:

millions except percentages **Notional Principal Amount**		**Reference Period**	**Mandatory Termination Date**	**Weighted-Average Interest Rate**
$	550	September 2016 - 2046	September 2020	6.418%
$	250	September 2016 - 2046	September 2022	6.809%
$	200	September 2017 - 2047	September 2018	6.049%
$	100	September 2017 - 2047	September 2020	6.891%
$	250	September 2017 - 2047	September 2021	6.570%
$	250	September 2017 - 2047	September 2023	6.761%

Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. As a result of prior extensions of reference-period start dates without settlement of the related interest-rate derivative obligations, the interest-rate derivatives in the Company's portfolio contain an other-than-insignificant financing element, and therefore, any settlements, collateralization, or cash payments for amendments related to these extended interest-rate derivatives are classified as cash flows from financing activities. Net cash payments related to settlements and amendments of interest-rate swap agreements were $112 million in 2017 and $274 million in 2016.

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10. Derivative Instruments (Continued)

Effect of Derivative Instruments—Balance Sheet The following summarizes the fair value of the Company's derivative instruments at December 31:

millions	Gross Derivative Assets		Gross Derivative Liabilities	
Balance Sheet Classification	**2017**	2016	**2017**	2016
Commodity derivatives				
Other current assets	**$ 7**	$ 10	**$ (1)**	$ (3)
Other assets	**2**	9	**—**	—
Other current liabilities	**45**	66	**(206)**	(201)
Other liabilities	**—**	—	**(2)**	(12)
	54	85	**(209)**	(216)
Interest-rate derivatives				
Other current assets	**14**	8	**—**	—
Other assets	**40**	23	**—**	—
Other current liabilities	**—**	—	**(236)**	(48)
Other liabilities	**—**	—	**(1,183)**	(1,328)
	54	31	**(1,419)**	(1,376)
Total derivatives	**$ 108**	$ 116	**$ (1,628)**	$ (1,592)

Effect of Derivative Instruments—Statement of Income The following summarizes gains and losses related to derivative instruments:

millions			
Classification of (Gain) Loss Recognized	**2017**	2016	2015
Commodity derivatives			
Gathering, processing, and marketing sales [(1)]	**$ (4)**	$ 6	$ (1)
(Gains) losses on derivatives, net	**3**	147	(367)
Interest-rate derivatives			
(Gains) losses on derivatives, net	**132**	139	268
Total (gains) losses on derivatives, net	**$ 131**	$ 292	$ (100)

(1) Represents the effect of Marketing and Trading Derivative Activities.

10. Derivative Instruments (Continued)

Credit-Risk Considerations The financial integrity of exchange-traded contracts, which are subject to nominal credit risk, is assured by NYMEX or ICE through systems of financial safeguards and transaction guarantees. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines and assesses the impact on the fair value of its counterparties' creditworthiness. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure.

The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities and routinely exercises its contractual right to offset gains and losses when settling with derivative counterparties. In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across derivative types.

The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's portfolio valuation versus negotiated credit thresholds. These credit thresholds generally require full or partial collateralization of the Company's obligations depending on certain credit-risk-related provisions, such as the Company's credit ratings from S&P and Moody's. As of December 31, 2017, the Company's long-term debt was rated investment grade (BBB) by both S&P and Fitch and below investment grade (Ba1) by Moody's. The Company may be required to post additional collateral with respect to its derivative instruments if its credit ratings decline below current levels. For example, based on year-end derivative positions, if Anadarko's credit rating were to be downgraded one level by either S&P or Moody's, the Company would be required to post additional collateral of up to approximately $50 million. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.4 billion (net of $170 million of collateral) at December 31, 2017, and $1.4 billion (net of $117 million of collateral) at December 31, 2016.

10. Derivative Instruments (Continued)

Fair Value Fair value of futures contracts is based on unadjusted quoted prices in active markets for identical assets or liabilities, which represent Level 1 inputs. Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs, because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, discount factors and implied market volatility.

The following summarizes the fair value of the Company's derivative assets and liabilities, by input level within the fair-value hierarchy:

millions	Level 1	Level 2	Level 3	Netting [1]	Collateral	Total
December 31, 2017						
Assets						
Commodity derivatives	**$ 1**	**$ 53**	**$ —**	**$ (46)**	**$ (1)**	**$ 7**
Interest-rate derivatives	**—**	**54**	**—**	**—**	**—**	**54**
Total derivative assets	**$ 1**	**$ 107**	**$ —**	**$ (46)**	**$ (1)**	**$ 61**
Liabilities						
Commodity derivatives	**$ (1)**	**$ (208)**	**$ —**	**$ 46**	**$ 3**	**$ (160)**
Interest-rate derivatives	**—**	**(1,419)**	**—**	**—**	**170**	**(1,249)**
Total derivative liabilities	**$ (1)**	**$ (1,627)**	**$ —**	**$ 46**	**$ 173**	**$ (1,409)**
December 31, 2016						
Assets						
Commodity derivatives	$ 2	$ 83	$ —	$ (69)	$ —	$ 16
Interest-rate derivatives	—	31	—	—	—	31
Total derivative assets	$ 2	$ 114	$ —	$ (69)	$ —	$ 47
Liabilities						
Commodity derivatives	$ (3)	$ (213)	$ —	$ 69	$ 6	$ (141)
Interest-rate derivatives	—	(1,376)	—	—	117	(1,259)
Total derivative liabilities	$ (3)	$ (1,589)	$ —	$ 69	$ 123	$ (1,400)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

11. Tangible Equity Units

In June 2015, the Company issued 9.2 million 7.50% TEUs at a stated amount of $50.00 per TEU and raised net proceeds of $445 million. Each TEU is comprised of a prepaid equity purchase contract for common units of WGP and a senior amortizing note. Subsequent to issuance, each TEU may be legally separated into the two components. The prepaid equity purchase contract is considered a freestanding financial instrument, indexed to WGP common units, and meets the conditions for equity classification.

Anadarko allocated the proceeds from the issuance of the TEUs to equity and debt based on the relative fair values of their respective components as follows:

millions, except price per TEU	Equity Component	Debt Component	Total
Price per TEU	$ 39.05	$ 10.95	$ 50.00
Gross proceeds	359	101	460
Less issuance costs	11	4	15
Net proceeds	$ 348	$ 97	$ 445

The prepaid equity purchase contracts were recorded in noncontrolling interests, net of issuance costs, and the senior amortizing notes were recorded in short-term debt and long-term debt on the Company's Consolidated Balance Sheet.

Equity Component Unless settled earlier at the holder's option, each purchase contract has a mandatory settlement date of June 7, 2018. Anadarko has a right to elect to issue and deliver shares of Anadarko Petroleum Corporation common stock (APC Shares) in lieu of delivering WGP common units at settlement. The Company will deliver WGP common units (or APC Shares) on the settlement date at the settlement rate based upon the applicable market value of WGP common units (or APC Shares) as follows:

	Settlement Rate per Purchase Contract [(1)]	
Applicable Market Value of WGP Common Units [(1)]	**WGP Common Units**	**APC Shares (if elected)**
Exceeds $68.0643 (Threshold Appreciation Price)	0.7346 units (Minimum Settlement Rate)	a number of shares equal to (a) the Minimum Settlement Rate, multiplied by the applicable market value of WGP common units, divided by (b) 98% of the applicable market value of APC Shares
Less than or equal to the Threshold Appreciation Price, but greater than or equal to $56.7083 (Reference Price)	a number of units equal to $50.00, divided by the applicable market value of WGP common units	a number of shares equal to $50.00, divided by 98% of the applicable market value of APC Shares
Less than the Reference Price	0.8817 units (Maximum Settlement Rate)	a number of shares equal to (a) the Maximum Settlement Rate, multiplied by the applicable market value of WGP common units, divided by (b) 98% of the applicable market value of APC Shares

(1) The applicable market value is the average of the daily volume-weighted average prices of WGP common units (or APC Shares) for the 20 consecutive trading days beginning on, and including, the 23rd scheduled trading day immediately preceding June 7, 2018.

11. Tangible Equity Units (Continued)

The WGP common units underlying the purchase contract are currently issued and outstanding, and are owned by a wholly owned subsidiary of Anadarko. In the event Anadarko elects to settle in APC Shares, the number of such shares issued and delivered upon settlement of each purchase contract is subject to adjustment and cannot exceed the APC Share cap of 4.0792 shares under any circumstance. The above fixed settlement rates for WGP common units and the APC Share cap are subject to adjustment upon the occurrence of certain specified dilutive events such as certain increases in the WGP distribution rate or the payment of dividends by Anadarko.

Debt Component Each senior amortizing note has an initial principal amount of $10.95 and bears interest at 1.50% per year. Beginning September 7, 2015, Anadarko began paying equal quarterly cash installments of $0.9375 per amortizing note (except for the September 7, 2015 installment payment, which was $0.9063 per amortizing note). The payments constitute a payment of interest and partial repayment of principal, with the aggregate per-year payments of principal and interest equating to a 7.50% cash payment with respect to each TEU. The senior amortizing notes have a final installment payment date of June 7, 2018, and are senior unsecured obligations of the Company. For activity related to the senior amortizing notes, see *Note 12—Debt and Interest Expense*.

12. Debt and Interest Expense

Debt Activity The following summarizes the Company's borrowing activity, after eliminating the effect of intercompany transactions:

	Carrying Value				
millions	WES	WGP [1]	Anadarko [2]	Consolidated	Description
Balance at December 31, 2015	$ 2,691	$ —	$ 12,957	$ 15,648	
Issuances	—	—	794	794	4.850% Senior Notes due 2021 [3]
	—	—	1,088	1,088	5.550% Senior Notes due 2026 [3]
	—	—	1,088	1,088	6.600% Senior Notes due 2046 [3]
	495	—	—	495	WES 4.650% Senior Notes due 2026
	203	—	—	203	WES 5.450% Senior Notes due 2044
Borrowings	—	—	1,750	1,750	364-Day Facility
	600	—	—	600	WES RCF
	—	28	—	28	WGP RCF
Repayments	—	—	(1,749)	(1,749)	5.950% Senior Notes due 2016
	—	—	(1,994)	(1,994)	6.375% Senior Notes due 2017
	—	—	(1,750)	(1,750)	364-Day Facility
	(900)	—	—	(900)	WES RCF
	—	—	(250)	(250)	Commercial paper notes, net
	—	—	(34)	(34)	TEUs - senior amortizing notes
Other, net	2	—	59	61	Amortization of discounts, premiums, and debt issuance costs
Balance at December 31, 2016	$ 3,091	$ 28	$ 11,959	$ 15,078	
Borrowings	**370**	**—**	**—**	**370**	WES RCF
Repayments	**—**	**—**	**(6)**	**(6)**	7.000% Debentures due 2027
	—	**—**	**(3)**	**(3)**	6.625% Debentures due 2028
	—	**—**	**(1)**	**(1)**	7.950% Debentures due 2029
	—	**—**	**(34)**	**(34)**	TEUs - senior amortizing notes
Other, net	**4**	**—**	**50**	**54**	Amortization of discounts, premiums, and debt issuance costs
Balance at December 31, 2017	**$ 3,465**	**$ 28**	**$ 11,965**	**$ 15,458**	

(1) Excludes WES.
(2) Excludes WES and WGP
(3) Represent senior notes issued in March 2016.

During the second quarter of 2016, the Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. In December 2016, the Company redeemed its remaining $750 million 6.375% Senior Notes due September 2017. The Company recognized losses of $155 million for the early retirement and redemption of these senior notes, which included $144 million of premiums paid.

12. Debt and Interest Expense (Continued)

Debt See *Note 8—Equity-Method Investments* for disclosure regarding Anadarko's notes payable related to its ownership of certain noncontrolling mandatorily redeemable interests that are not included in the Company's reported debt balance and do not affect consolidated interest expense. The following summarizes the Company's outstanding debt, including capital lease obligations, after eliminating the effect of intercompany transactions:

	December 31, 2017			
millions	WES	WGP [1]	Anadarko [2]	Consolidated
7.050% Debentures due 2018	$ —	$ —	$ 114	$ 114
TEUs - senior amortizing notes due 2018	—	—	17	17
WES 2.600% Senior Notes due 2018	350	—	—	350
6.950% Senior Notes due 2019	—	—	300	300
8.700% Senior Notes due 2019	—	—	600	600
4.850% Senior Notes due 2021	—	—	800	800
WES 5.375% Senior Notes due 2021	500	—	—	500
WES 4.000% Senior Notes due 2022	670	—	—	670
3.450% Senior Notes due 2024	—	—	625	625
6.950% Senior Notes due 2024	—	—	650	650
WES 3.950% Senior Notes due 2025	500	—	—	500
WES 4.650% Senior Notes due 2026	500	—	—	500
5.550% Senior Notes due 2026	—	—	1,100	1,100
7.500% Debentures due 2026	—	—	112	112
7.000% Debentures due 2027	—	—	48	48
7.125% Debentures due 2027	—	—	150	150
6.625% Debentures due 2028	—	—	14	14
7.150% Debentures due 2028	—	—	235	235
7.200% Debentures due 2029	—	—	135	135
7.950% Debentures due 2029	—	—	116	116
7.500% Senior Notes due 2031	—	—	900	900
7.875% Senior Notes due 2031	—	—	500	500
Zero Coupon Senior Notes due 2036	—	—	2,360	2,360
6.450% Senior Notes due 2036	—	—	1,750	1,750
7.950% Senior Notes due 2039	—	—	325	325
6.200% Senior Notes due 2040	—	—	750	750
4.500% Senior Notes due 2044	—	—	625	625
WES 5.450% Senior Notes due 2044	600	—	—	600
6.600% Senior Notes due 2046	—	—	1,100	1,100
7.730% Debentures due 2096	—	—	61	61
7.500% Debentures due 2096	—	—	78	78
7.250% Debentures due 2096	—	—	49	49
WES RCF	370	—	—	370
WGP RCF	—	28	—	28
Total borrowings at face value	$ 3,490	$ 28	$ 13,514	$ 17,032
Net unamortized discounts, premiums, and debt issuance costs [3]	(25)	—	(1,549)	(1,574)
Total borrowings [4]	3,465	28	11,965	15,458
Capital lease obligations	—	—	231	231
Less short-term debt	—	—	142	142
Total long-term debt	$ 3,465	$ 28	$ 12,054	$ 15,547

12. Debt and Interest Expense (Continued)

	December 31, 2016			
millions	WES	WGP [1]	Anadarko [2]	Consolidated
7.050% Debentures due 2018	—	—	114	114
TEUs - senior amortizing notes due 2018	—	—	51	51
WES 2.600% Senior Notes due 2018	350	—	—	350
6.950% Senior Notes due 2019	—	—	300	300
8.700% Senior Notes due 2019	—	—	600	600
4.850% Senior Notes due 2021	—	—	800	800
WES 5.375% Senior Notes due 2021	500	—	—	500
WES 4.000% Senior Notes due 2022	670	—	—	670
3.450% Senior Notes due 2024	—	—	625	625
6.950% Senior Notes due 2024	—	—	650	650
WES 3.950% Senior Notes due 2025	500	—	—	500
WES 4.650% Senior Notes due 2026	500	—	—	500
5.550% Senior Notes due 2026	—	—	1,100	1,100
7.500% Debentures due 2026	—	—	112	112
7.000% Debentures due 2027	—	—	54	54
7.125% Debentures due 2027	—	—	150	150
6.625% Debentures due 2028	—	—	17	17
7.150% Debentures due 2028	—	—	235	235
7.200% Debentures due 2029	—	—	135	135
7.950% Debentures due 2029	—	—	117	117
7.500% Senior Notes due 2031	—	—	900	900
7.875% Senior Notes due 2031	—	—	500	500
Zero Coupon Senior Notes due 2036	—	—	2,360	2,360
6.450% Senior Notes due 2036	—	—	1,750	1,750
7.950% Senior Notes due 2039	—	—	325	325
6.200% Senior Notes due 2040	—	—	750	750
4.500% Senior Notes due 2044	—	—	625	625
WES 5.450% Senior Notes due 2044	600	—	—	600
6.600% Senior Notes due 2046	—	—	1,100	1,100
7.730% Debentures due 2096	—	—	61	61
7.500% Debentures due 2096	—	—	78	78
7.250% Debentures due 2096	—	—	49	49
WGP RCF	—	28	—	28
Total borrowings at face value	$ 3,120	$ 28	$ 13,558	$ 16,706
Net unamortized discounts, premiums, and debt issuance costs [3]	(29)	—	(1,599)	(1,628)
Total borrowings [4]	3,091	28	11,959	15,078
Capital lease obligations	—	—	245	245
Less short-term debt	—	—	42	42
Total long-term debt	$ 3,091	$ 28	$ 12,162	$ 15,281

(1) Excludes WES.

(2) Excludes WES and WGP.

(3) Unamortized discounts, premiums, and debt issuance costs are amortized over the term of the related debt. Debt issuance costs related to RCFs are included in other current assets and other assets on the Company's Consolidated Balance Sheets.

(4) The Company's outstanding borrowings, except for borrowings under the WGP RCF, are senior unsecured.

12. Debt and Interest Expense (Continued)

In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero Coupons. The Zero Coupons mature in 2036 and have an aggregate principal amount due at maturity of approximately $2.4 billion, reflecting a yield to maturity of 5.24%. The Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value of the outstanding Zero Coupons. The accreted value of the outstanding Zero Coupons was $894 million at December 31, 2017. Anadarko's Zero Coupons were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2017, as the Company has the ability and intent to refinance these obligations using long-term debt, should the put be exercised.

Scheduled Maturities Total principal amount of debt maturities related to borrowings for the five years ending December 31, 2022, excluding the potential repayment of the outstanding Zero Coupons that may be put by the holders to the Company annually, were as follows:

	Principal Amount of Debt Maturities			
millions	WES	WGP [1]	Anadarko [2]	Consolidated
2018	$ 350	$ —	$ 131	$ 481
2019	—	28	900	928
2020	370	—	—	370
2021	500	—	800	1,300
2022	670	—	—	670

(1) Excludes WES.
(2) Excludes WES and WGP.

Fair Value The Company uses a market approach to determine the fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. The estimated fair value of the Company's total borrowings was $17.7 billion at December 31, 2017, and $17.1 billion at December 31, 2016.

Anadarko Borrowings At December 31, 2017, Anadarko had a $3.0 billion senior unsecured RCF (APC RCF) and a $2.0 billion 364-day senior unsecured RCF (364-Day Facility). In January 2018, the Company amended the APC RCF to extend the maturity date to January 2022 and amended the 364-Day Facility to extend the maturity date to January 2019.

Borrowings under the APC RCF and the 364-Day Facility (collectively, the Credit Facilities) generally bear interest under one of two rate options, at Anadarko's election, using either LIBOR (or Euro Interbank Offered Rate in the case of borrowings under the APC RCF denominated in Euro) or an alternate base rate, in each case plus an applicable margin ranging from 0.00% to 1.65% for the APC RCF and 0.00% to 1.675% for the 364-Day Facility. The applicable margin will vary depending on Anadarko's credit ratings.

The Credit Facilities contain certain customary affirmative and negative covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% (excluding the effect of non-cash write-downs), and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. At December 31, 2017, the Company had no outstanding borrowings under the Credit Facilities and was in compliance with all covenants.

In January 2015, the Company initiated a commercial paper program, which allows for a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the APC RCF. The maturities of the commercial paper notes may vary, but may not exceed 397 days. As a result of Moody's credit rating on Anadarko, the Company's access to the commercial paper market has been eliminated. The Company has not issued commercial paper notes since the downgrade and had no outstanding borrowings under the commercial paper program at December 31, 2017.

12. Debt and Interest Expense (Continued)

WES and WGP Borrowings In July 2016, WES completed a public offering of $500 million aggregate principal amount of 4.650% Senior Notes due July 2026. Net proceeds were used to repay a portion of the amount outstanding under WES's $1.2 billion senior unsecured RCF previously maturing in February 2019 (WES RCF), which is expandable to $1.5 billion. In October 2016, WES completed a public offering of $200 million aggregate principal amount of 5.450% Senior Notes due April 2044. Net proceeds were primarily used to repay amounts outstanding under the WES RCF, and the remaining proceeds were used for general partnership purposes, including capital expenditures. In December 2016, WES amended the WES RCF to extend the maturity date to February 2020. In February 2018, the WES RCF was amended to extend the maturity date from February 2020 to February 2023 and expand the borrowing capacity to $1.5 billion.

Borrowings under the WES RCF bear interest at LIBOR plus an applicable margin ranging from 0.975% to 1.45% depending on WES's credit rating, or the greatest of (i) rates at a margin above the one-month LIBOR, (ii) the federal funds rate, or (iii) prime rates offered by certain designated banks. At December 31, 2017, WES had outstanding borrowings under its RCF of $370 million at an interest rate of 2.87%, had outstanding letters of credit of $5 million, and had available borrowing capacity of $825 million. At December 31, 2017, WES was in compliance with all covenants. WES's $350 million 2.600% Senior Notes due August 2018 were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2017, as WES has the ability and intent to refinance these obligations using long-term debt.

In March 2016, WGP entered into a $250 million senior secured RCF maturing in March 2019 (WGP RCF), which is expandable to $500 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions. Obligations under the WGP RCF are secured by a first priority lien on all of WGP's assets (not including the consolidated assets of WES), as well as all equity interests owned by WGP. Borrowings under the WGP RCF bear interest at LIBOR (with a floor of 0%), plus applicable margins ranging from 2.00% to 2.75% depending on WGP's consolidated leverage ratio, or at a base rate equal to the greatest of (i) the prime rate, (ii) the federal funds rate plus 0.50%, or (iii) LIBOR plus 1.00%, in each case plus applicable margins ranging from 1.00% to 1.75% based upon WGP's consolidated leverage ratio. At December 31, 2017, WGP had outstanding borrowings under its RCF of $28 million at an interest rate of 3.57%, had available borrowing capacity of $222 million, and was in compliance with all covenants. In February 2018, WGP voluntarily reduced the aggregate commitments of the lenders under the WGP RCF to $35 million.

12. Debt and Interest Expense (Continued)

Capital Lease Obligations Construction of a FPSO for the Company's TEN field in Ghana commenced in 2013. The Company recognized an asset and related obligation for its approximate 19% nonoperated participating interest share during the construction period. Upon completion of the construction in the third quarter of 2016, the Company reported the asset and related obligation as a capital lease of $225 million for the Company's proportionate share of the fair value of the FPSO. The FPSO lease provides for an initial term of 10 years with annual renewal periods for an additional 10 years, annual purchase options that decrease over time, and no residual value guarantees. The capital lease asset will be depreciated over the estimated proved reserves of the TEN field using the UOP method, with the associated depreciation included in DD&A in the Company's Consolidated Statement of Income. The capital lease obligation will be accreted to the present value of the minimum lease payments using the effective interest method. The Company made capital lease payments of $44 million in 2017.

At December 31, 2017, future minimum lease payments related to the Company's capital leases were:

millions	
2018	$ 53
2019	42
2020	43
2021	42
2022	42
Remaining years	365
Total future minimum lease payments	$ 587
Less portion representing imputed interest	356
Capital lease obligations	$ 231

Interest Expense The following summarizes interest expense for the years ended December 31:

millions	**2017**	2016	2015
Debt and other	**$ 1,003**	$ 1,022	$ 989
Capitalized interest	**(71)**	(132)	(164)
Total interest expense	**$ 932**	$ 890	$ 825

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

13. Income Taxes

Following the adoption of the Tax Reform Legislation on December 22, 2017, the Company recognized a one-time deferred tax benefit of $1.2 billion, inclusive of a $236 million increase to the Company's valuation allowance on its foreign tax credit carryforwards, due to the remeasurement of its U.S. deferred tax assets and liabilities based on the 21% corporate tax rate. The Company did not recognize U.S. income tax expense related to the deemed repatriation of its foreign income as required by the Tax Reform Legislation as any U.S. taxes will be offset with foreign tax credits.

The Company regards all of these items as provisional amounts since the amounts are based on reasonable estimates of material temporary difference changes in 2017 and its state tax apportionment ratios. The provisional federal tax benefit is included in the deferred tax liability balance as presented on the Company's Consolidated Balance Sheet. The Company expects to adjust this provisional amount in subsequent periods when more information becomes available as the Company prepares its 2017 federal and state tax filings. The Company will complete its analysis of the income tax effects of the Tax Reform Legislation before the end of the measurement period on December 21, 2018.

The following summarizes components of income tax expense (benefit) for the years ended December 31:

millions	**2017**	2016	2015
Current			
Federal	**$ 236**	$ (140)	$ (177)
State	**48**	(1)	(18)
Foreign	**414**	378	495
	698	237	300
Deferred			
Federal	**(2,082)**	(1,020)	(2,929)
State	**(17)**	(148)	(145)
Foreign	**(76)**	(90)	(103)
	(2,175)	(1,258)	(3,177)
Total income tax expense (benefit)	**$ (1,477)**	$ (1,021)	$ (2,877)

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

13. Income Taxes (Continued)

Total income taxes differed from the amounts computed by applying the U.S. federal statutory income tax rate to income (loss) before income taxes. The following summarizes the sources of these differences for the years ended December 31:

millions except percentages	**2017**	2016	2015
Income (loss) before income taxes			
Domestic	**$ (1,322)**	$ (3,728)	$ (9,155)
Foreign	**(366)**	(101)	(534)
Total	**$ (1,688)**	$ (3,829)	$ (9,689)
U.S. federal statutory tax rate	**35%**	35%	35%
Tax computed at the U.S. federal statutory rate	**$ (591)**	$ (1,340)	$ (3,391)
(Income) loss attributable to noncontrolling interests	**(85)**	(92)	42
Adjustments resulting from			
State income taxes (net of federal income tax benefit)	**25**	(108)	(81)
U.S. federal tax reform	**(1,168)**	—	—
Tax impact from foreign operations	**166**	80	299
Non-deductible Algerian exceptional profits tax	**110**	106	102
Net changes in uncertain tax positions	**90**	90	54
Dispositions of non-deductible goodwill	**6**	205	62
Other, net	**(30)**	38	36
Total income tax expense (benefit)	**$ (1,477)**	$ (1,021)	$ (2,877)
Effective tax rate	**88%**	27%	30%

The following summarizes components of total deferred taxes at December 31:

millions	**2017**	2016
Federal	**$ (1,758)**	$ (3,805)
State, net of federal	**(200)**	(173)
Foreign	**(255)**	(332)
Total deferred taxes	**$ (2,213)**	$ (4,310)

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

13. Income Taxes (Continued)

The following summarizes tax effects of temporary differences that give rise to significant portions of the deferred tax assets (liabilities) at December 31:

millions	**2017**	2016
Deferred tax liabilities		
Oil and gas exploration and development operations	**$ (2,599)**	$ (5,025)
Midstream and other depreciable properties	**(543)**	(870)
Mineral operations	**(312)**	(550)
Other	**(54)**	(147)
Gross long-term deferred tax liabilities	**(3,508)**	(6,592)
Deferred tax assets		
Oil and gas exploration and development costs	**309**	250
Foreign and state net operating loss carryforwards	**562**	648
U.S. foreign tax credit carryforwards	**2,685**	1,834
Compensation and benefit plans	**365**	672
Mark to market on derivatives	**232**	324
Other	**166**	309
Gross long-term deferred tax assets	**4,319**	4,037
Valuation allowances on deferred tax assets not expected to be realized	**(3,024)**	(1,755)
Net long-term deferred tax assets	**1,295**	2,282
Total deferred taxes	**$ (2,213)**	$ (4,310)

The valuation allowance primarily relates to U.S. foreign tax credit carryforwards and foreign and state net operating loss carryforwards, which reduces the Company's net deferred tax asset to an amount that will more likely than not be realized within the carryforward period.

The following summarizes changes in the balance of valuation allowances on deferred tax assets:

millions	**2017**	2016	2015
Balance at January 1	**$ (1,755)**	$ (1,403)	$ (864)
Changes due to U.S. foreign tax credits	**(1,287)**	(477)	(384)
Changes due to foreign and state net operating loss carryforwards	**75**	13	10
Changes due to foreign capitalized costs	**(57)**	112	(165)
Balance at December 31	**$ (3,024)**	$ (1,755)	$ (1,403)

Tax carryforwards available for use on future income tax returns, prior to valuation allowance, at December 31, 2017, were as follows:

millions	**Domestic**	**Foreign**	**Expiration**
Net operating loss—foreign	$ —	$ 1,184	2018 - Indefinite
Net operating loss—state	$ 4,452	$ —	2018-2037
Foreign tax credits	$ 2,685	$ —	2023-2028
Texas margins tax credit	$ 30	$ —	2026

13. Income Taxes (Continued)

The following summarizes taxes receivable (payable) related to income tax expense (benefit) at December 31:

millions **Balance Sheet Classification**	**2017**	2016
Income taxes receivable		
Accounts receivable—other	**$ 53**	$ 180
Other assets	**101**	67
	154	247
Income taxes (payable)		
Other current liabilities	**(71)**	(6)
Total net income taxes receivable (payable)	**$ 83**	$ 241

Changes in the balance of unrecognized tax benefits, excluding interest and penalties on uncertain tax positions, were as follows:

	Assets (Liabilities)		
millions	**2017**	2016	2015
Balance at January 1	**$ (1,456)**	$ (1,780)	$ (1,687)
Increases related to prior-year tax positions	**(15)**	(86)	(99)
Decreases related to prior-year tax positions	**214**	436	89
Increases related to current-year tax positions	**(72)**	(26)	(263)
Settlements	**12**	—	180
Balance at December 31	**$ (1,317)**	$ (1,456)	$ (1,780)

The December 31, 2017 ending balance of unrecognized tax benefits includes potential benefits of $1.29 billion, of which, if recognized, $1.25 billion would affect the effective tax rate on income. Also included are benefits of $27 million related to tax positions for which the ultimate deductibility is highly certain, but the timing of such deductibility is uncertain.

The Company recognized a net tax benefit of $346 million as of December 31, 2017, and $576 million as of December 31, 2016, related to the deduction of its 2015 settlement payment for the Tronox Adversary Proceeding. This benefit is net of uncertain tax positions of $1.2 billion as of December 31, 2017, and $1.3 billion as of December 31, 2016, due to uncertainty related to the deductibility of the settlement payment. The tax benefit and related uncertain tax position decreased as a result of the Tax Reform Legislation. Due to the deduction of the settlement payment, the Company had a net operating loss carryback for 2015, which resulted in a tentative tax refund of $881 million in 2016. The IRS has audited this position and issued a draft notice of proposed adjustment denying the deductibility of the settlement payment. The Company disagrees and plans to defend its tax position. Accordingly, the Company has not revised its estimate of the benefit that will ultimately be realized. It is reasonably possible the amount of uncertain tax position and/or tax benefit could materially change as the Company defends its tax position through the appeals process and other available avenues. The Company could be required to repay all or a portion of the tentative refund received with interest prior to determining the final outcome of its position either upon IRS request or litigation of the matter in District or Federal Claims Court. If the payment is ultimately determined not to be deductible, the Company would be required to repay the tentative refund received plus interest and reverse the net benefit of $346 million previously recognized in its consolidated financial statements.

13. Income Taxes (Continued)

Income tax audits and the Company's acquisition and divestiture activity have given rise to tax disputes in U.S. and foreign jurisdictions. See *Note 17—Contingencies—Litigation.* Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $20 million to $50 million due to settlements with taxing authorities or lapse in statutes of limitation. Management does not believe that the final resolution of outstanding tax audits and litigation would have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows, except for the potential impact related to the outcome of the deductibility of the Tronox settlement payment.

The Company accrued approximately $86 million of interest related to uncertain tax positions at December 31, 2017, and $31 million at December 31, 2016. The Company recognized interest and penalties in income tax expense (benefit) of $55 million during 2017 and $21 million during 2016.

Anadarko is subject to audit by tax authorities in the U.S. federal, state, and local tax jurisdictions as well as in various foreign jurisdictions. The following lists the tax years subject to examination by major tax jurisdiction:

	Tax Years
United States	2012-2017
Algeria	2014-2017
Ghana	2014-2017

14. Asset Retirement Obligations

The majority of Anadarko's AROs relate to the plugging of wells and the related abandonment of oil and gas properties. Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected timing of settlement. The following summarizes changes in the Company's AROs:

millions	**2017**	2016
Carrying amount at January 1	**$ 2,931**	$ 2,059
Liabilities acquired [(1)]	**4**	813
Liabilities incurred	**191**	93
Property dispositions	**(154)**	(88)
Liabilities settled	**(135)**	(225)
Accretion expense	**144**	100
Revisions in estimated liabilities	**(187)**	179
Carrying amount at December 31	**$ 2,794**	$ 2,931

(1) In December 2016, the Company closed the GOM Acquisition. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* for additional information.

15. Conveyance of Future Hard-Minerals Royalty Revenues

During the first quarter of 2016, the Company conveyed a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party for $413 million, net of transaction costs. Such conveyance entitles the third party to receive up to $553 million in future royalty revenue over a period of not less than 10 years and not greater than 15 years. Additionally, such third party is entitled to receive 3% of the aggregate royalties earned during the first 10 years between $800 million and $900 million and 4% of the aggregate royalties earned during the first 10 years that exceed $900 million. Generally, such third party relies solely on the royalty payments to recover its investment and, as such, has the risk of the royalties not being sufficient to recover its investment over the term of the conveyance.

Proceeds from this transaction were accounted for as deferred revenues and are included in other current liabilities and other long-term liabilities - other on the Company's Consolidated Balance Sheet. The deferred revenues will be amortized to other revenues, included in gains (losses) on divestitures and other, net, on a unit-of-revenue basis over the term of the agreement. Net proceeds received from the third party were reported in financing activities on the Company's Consolidated Statement of Cash Flows. Semi-annual payments to the third party are scheduled on March 1 and September 1 of each year through March 1, 2026. The specified future amounts that the Company expects to pay and the payment timing are subject to change based upon the actual royalties received by the Company during the term of the conveyance. Royalties received by Anadarko under this agreement are reported in operating activities on the Company's Consolidated Statement of Cash Flows. The semi-annual payments to the third party, up to the aggregate amount of the $413 million net proceeds the Company received for the conveyance in the first quarter of 2016, are reported in financing activities on the Company's Consolidated Statement of Cash Flows. Any additional payments to the third party are reported in operating activities on the Company's Consolidated Statement of Cash Flows to offset the royalties received.

During the year ended December 31, 2017, the Company amortized $38 million of deferred revenues as a result of this agreement. The Company made two semi-annual payments totaling $50 million for royalties in 2017. The following summarizes the remaining amounts that the Company expects to pay, prior to the potential 3% to 4% of any excess described above:

millions	
2018	$ 50
2019	52
2020	56
2021	57
2022	58
Later years	204
Total	$ 477

16. Commitments

Operating Leases At December 31, 2017, the Company had $611 million in long-term drilling rig commitments that are accounted for as operating leases. These drilling rig operating leases expire at various dates through 2020. The Company also had $323 million of various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, aircraft, and vessels. These operating leases expire at various dates through 2033. Certain of these operating leases contain residual value guarantees at the end of the lease term of $82 million at December 31, 2017. No liability was accrued for residual value guarantees. In addition, these operating leases include options to purchase the leased property during or at the end of the lease term for the fair market value or other specified amount at that time. The following summarizes future minimum lease payments under operating leases at December 31, 2017:

millions		
2018	$	465
2019		259
2020		94
2021		38
2022		26
Later years		52
Total future minimum lease payments	$	934

Anadarko has entered into various agreements to secure drilling rigs necessary to support the execution of its drilling plans over the next several years. The table of future minimum lease payments above includes $586 million related to four offshore drilling vessels and $25 million related to certain contracts for U.S. onshore drilling rigs. Lease payments associated with the drilling of exploratory wells and development wells net of amounts billed to partners will initially be capitalized as a component of oil and gas properties and either depreciated or impaired in future periods or written off as exploration expense.

Total rent expense, net of sublease income and amounts capitalized, amounted to $55 million in 2017, $73 million in 2016, and $77 million in 2015. Total rent expense included contingent rent expense related to transportation and processing fees of $3 million in 2017, $6 million in 2016, and $17 million in 2015.

Other Commitments Anadarko has various long-term contractual commitments pertaining to oil and natural-gas activities such as work-related commitments for drilling wells, obtaining and processing seismic data, and fulfilling rig commitments. Anadarko also enters into various processing, transportation, storage, and purchase agreements to access markets and provide flexibility to sell its oil, natural gas, and NGLs in certain areas. These agreements expire at various dates through 2033. The following summarizes the gross aggregate future payments under these contracts at December 31, 2017:

millions		
2018	$	1,267
2019		1,069
2020		968
2021		756
2022		605
Later years		1,437
Total [1]	$	6,102

[1] Excludes purchase commitments for jointly owned fields and facilities for which the Company is not the operator.

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17. Contingencies

The Company is a defendant in a number of lawsuits, is involved in governmental proceedings, and is subject to regulatory controls arising in the ordinary course of business, including personal injury claims; property damage claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. As of December 31, 2017, the Company had $16 million accrued for litigation-related contingencies. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

Litigation In December 2008, Anadarko sold its interest in the Peregrino heavy-oil field offshore Brazil. The Company is currently litigating a dispute with the Brazilian tax authorities regarding the tax rate applicable to the transaction. In December 2008, the Company deposited the amount of tax originally in dispute in a Brazilian real-denominated judicially-controlled Brazilian bank account pending final resolution of the matter. At December 31, 2017, the deposit of $103 million is included in other assets on the Company's Consolidated Balance Sheet.

In July 2009, the lower judicial court ruled in favor of the Brazilian tax authorities. The Company appealed this decision to the Brazilian Regional courts, which upheld the lower court's ruling in favor of the Brazilian tax authorities in December 2011. In April 2012, the Company filed simultaneous appeals to the Brazilian Superior Court and the Brazilian Supreme Court. The appeal to the Brazilian Supreme Court has been stayed pending a decision in the Superior Court appeal.

In August 2013, following a determination by an administrative court in a related matter that the amount of tax in dispute was not calculated properly, the Company filed a petition requesting the withdrawal of a portion of the judicial deposit to the extent it exceeds the amount of tax currently in dispute and any interest on such excess amount. In April 2015, the Company's petition was denied. The Company appealed this decision. The appeal was denied in November 2015.

The Company believes that it will more likely than not prevail in the Brazilian Superior Court and the Brazilian Supreme Court. Therefore, no tax liability has been recorded for Peregrino divestiture-related litigation at December 31, 2017. The Company continues to vigorously defend its tax position in the Brazilian courts.

Guarantees and Indemnifications The Company provides certain indemnifications in relation to asset dispositions. These indemnifications typically relate to disputes, litigation, or tax matters existing at the date of disposition.

Environmental Matters Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. The Company's Consolidated Balance Sheets include liabilities for remediation and reclamation obligations of $113 million at December 31, 2017, and $118 million at December 31, 2016. The current portion of these amounts was included in other current liabilities and the long-term portion of these amounts was included in other long-term liabilities—other on the Company's Consolidated Balance Sheets. The Company continually monitors remediation and reclamation processes and adjusts its liability for these obligations as necessary.

18. Restructuring Charges

In the first quarter of 2016, the Company initiated a workforce reduction program to align the size and composition of its workforce with its expected future operating and capital plans. Employee notifications related to the workforce reduction program were completed by June 30, 2016. The Company recognized restructuring charges included in G&A in the Company's Consolidated Statements of Income of $389 million during the year ended December 31, 2016. All restructuring charges were recognized in 2016, with the exception of $21 million, primarily related to defined-benefit pension settlement expense, which was recognized during 2017 for lump-sum payments to terminated participants.

19. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans

The Company has contributory and non-contributory defined-benefit pension plans, which include both qualified and supplemental plans. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree and, in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is non-contributory.

The following sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2017 and 2016, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2017 and 2016:

	Pension Benefits		Other Benefits	
millions	**2017**	2016	**2017**	2016
Change in benefit obligation				
Benefit obligation at beginning of year	**$ 2,301**	$ 2,431	**$ 296**	$ 266
Service cost	**87**	99	**2**	3
Interest cost	**84**	95	**12**	12
Actuarial (gain) loss [1]	**130**	211	**14**	34
Participant contributions	**—**	—	**5**	4
Benefit payments	**(396)**	(513)	**(27)**	(23)
Foreign-currency exchange-rate changes	**12**	(22)	**—**	—
Benefit obligation at end of year [2]	**$ 2,218**	$ 2,301	**$ 302**	$ 296
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,340**	$ 1,674	**$ —**	$ —
Actual return on plan assets	**209**	107	**—**	—
Employer contributions	**254**	101	**22**	19
Participant contributions	**—**	—	**5**	4
Benefit payments	**(396)**	(513)	**(27)**	(23)
Foreign-currency exchange-rate changes	**17**	(29)	**—**	—
Fair value of plan assets at end of year	**$ 1,424**	$ 1,340	**$ —**	$ —
Funded status of the plans at end of year	**$ (794)**	$ (961)	**$ (302)**	$ (296)
Amounts recognized on the balance sheet				
Other assets	**$ 58**	$ 44	**$ —**	$ —
Other current liabilities	**(16)**	(66)	**(21)**	(23)
Other long-term liabilities—other	**(836)**	(939)	**(281)**	(273)
Total	**$ (794)**	$ (961)	**$ (302)**	$ (296)
Amounts recognized in accumulated other comprehensive income				
Prior service (credit) cost	**$ —**	$ —	**$ (26)**	$ (50)
Net actuarial (gain) loss	**501**	616	**14**	—
Total	**$ 501**	$ 616	**$ (12)**	$ (50)

(1) Includes $19 million of settlement losses for pension benefits at December 31, 2017, and $44 million of termination benefits at December 31, 2016, associated with the Company's workforce reduction program initiated in the first quarter of 2016. See *Note 18—Restructuring Charges*.

(2) The accumulated benefit obligation for all defined-benefit pension plans was $1.9 billion at December 31, 2017 and $2.0 billion at December 31, 2016.

19. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The following summarizes the Company's defined-benefit pension plans with accumulated benefit obligations in excess of plan assets for the years ended December 31:

millions	**2017**	2016
Projected benefit obligation	**$ 2,079**	$ 2,175
Accumulated benefit obligation	**1,749**	1,866
Fair value of plan assets	**1,227**	1,171

The following summarizes the Company's pension and other postretirement benefit cost for the years ended December 31:

	Pension Benefits			**Other Benefits**		
millions	**2017**	2016	2015	**2017**	2016	2015
Components of net periodic benefit cost						
Service cost	**$ 87**	$ 99	$ 118	**$ 2**	$ 3	$ 9
Interest cost	**84**	95	101	**12**	12	15
Expected (return) loss on plan assets	**(84)**	(97)	(109)	**—**	—	—
Amortization of net actuarial (gain) loss	**25**	42	52	**—**	—	—
Amortization of net prior service (credit) cost	**(1)**	—	—	**(24)**	(25)	(4)
Settlement expense [(1)]	**91**	146	11	**—**	—	—
Termination benefits expense [(1)]	**4**	44	—	**—**	—	—
Curtailment expense [(1)]	**—**	8	—	**—**	—	—
Net periodic benefit cost	**$ 206**	$ 337	$ 173	**$ (10)**	$ (10)	$ 20

(1) Settlement expense, termination benefits expense, and curtailment expense for 2016 relate to the workforce reduction program initiated in the first quarter of 2016. See *Note 18—Restructuring Charges*.

The following summarizes the amounts recognized in other comprehensive income (before tax benefit) for the years ended December 31:

	Pension Benefits			**Other Benefits**		
millions	**2017**	2016	2015	**2017**	2016	2015
Amounts recognized in other comprehensive income (expense)						
Net actuarial gain (loss)	**$ —**	$ (150)	$ 22	**$ (14)**	$ (25)	$ 27
Amortization of net actuarial (gain) loss	**116**	188	63	**—**	—	—
Net prior service credit (cost)	**—**	—	—	**—**	—	89
Amortization of net prior service (credit) cost	**(1)**	—	—	**(24)**	(34)	(4)
Total amounts recognized in other comprehensive income (expense)	**$ 115**	$ 38	$ 85	**$ (38)**	$ (59)	$ 112

The Company amortizes prior service costs (credits) on a straight-line basis over the average remaining service period of employees expected to receive benefits under each plan. Actuarial gains and losses that exceed 10% of the greater of the projected benefit obligation and the market-related value of assets are amortized over the average remaining service period of participating employees expected to receive benefits under each plan. In 2018, an estimated $24 million of net actuarial loss and $24 million of net prior service credit for the pension and other postretirement plans will be amortized from accumulated other comprehensive income into net periodic benefit cost.

19. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement plans include the discount rate, the expected long-term rate of return on plan assets (for funded pension plans), the rate of future compensation increases, and inflation (for postretirement plans). Other assumptions involve demographic factors such as retirement age, mortality, and turnover. The Company evaluates and updates its actuarial assumptions at least annually.

Accumulated and projected benefit obligations are measured as the present value of future cash payments. The Company discounts those cash payments using a discount rate that reflects the weighted average of market-observed yields for select high-quality (AA-rated) fixed-income securities with cash flows that correspond to the expected amounts and timing of benefit payments. The discount-rate assumption used by the Company represents an estimate of the interest rate at which the pension and other postretirement benefit obligations could effectively be settled on the measurement date. Assumed rates of compensation increases for active participants vary by age group, with the resulting weighted-average assumed rate (weighted by the plan-level benefit obligation) provided in the preceding table.

The following summarizes the weighted-average assumptions used by the Company in determining the pension and other postretirement benefit obligations and net periodic benefit cost for the years ended December 31:

	Pension Benefits			**Other Benefits**		
	2017	2016	2015	**2017**	2016	2015
Benefit obligation assumptions						
Discount rate	**3.62%**	4.06%	4.50%	**3.75%**	4.26%	5.00%
Rates of increase in compensation levels	**5.36%**	5.40%	5.25%	**5.46%**	5.48%	5.50%
Net periodic benefit cost assumptions						
Discount rate	**4.06%**	4.62%	4.00%	**4.26%**	5.00%	4.25%
Long-term rate of return on plan assets	**6.12%**	6.77%	6.75%	**N/A**	N/A	N/A
Rates of increase in compensation levels	**5.40%**	5.34%	5.25%	**5.48%**	5.41%	5.25%

An annual rate of increase indexed to the Consumer Price Index is assumed for purposes of measuring other postretirement benefit obligations. A rate of 2.00% at December 31, 2017 and 2016, and 1.75% at December 31, 2015 was assumed for purposes of measuring other postretirement benefit obligations.

19. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Plan Assets

Investment Policies and Strategies The Company has adopted a balanced, diversified investment strategy, with the intent of maximizing returns without exposure to undue risk. Investments are typically made through investment managers across several investment categories (domestic equity securities, international equity securities, fixed-income securities, real estate, hedge funds, and private equity), with selective exposure to Growth/Value investment styles. Performance for each investment is measured relative to the appropriate index benchmark for its category. Target asset-allocation percentages by major category are 45%-55% equity securities, 20%-30% fixed income, and up to 25% in a combination of other investments such as real estate, hedge funds, and private equity. Investment managers have full discretion as to investment decisions regarding funds under their management to the extent permitted within investment guidelines.

Although investment managers may, at their discretion and within investment guidelines, invest in Anadarko securities, there are no direct investments in Anadarko securities included in plan assets. There may be, however, indirect investments in Anadarko securities through the plans' collective fund investments. The expected long-term rate of return on plan assets assumption was determined using the year-end 2017 pension investment balances by asset class and expected long-term asset allocation. The expected return for each asset class reflects capital-market projections formulated using a forward-looking building-block approach while also taking into account historical return trends and current market conditions. Equity returns generally reflect long-term expectations of real earnings growth, dividend yield, changes in valuation, and inflation. Returns on fixed-income securities are generally developed based on expected cash returns and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset-class returns are generally derived from their relationship to the equity and fixed-income markets.

Risks and Uncertainties The plan assets include various investment securities that are exposed to various risks such as interest-rate, credit, and market risks. Due to the level of risk associated with certain investment securities, it is possible that changes in the values of investment securities could significantly impact the plan assets.

The plan assets may include securities with contractual cash flows such as asset-backed securities, collateralized mortgage obligations, and commercial mortgage-backed securities, including securities backed by subprime mortgage loans. The value, liquidity, and related income of those securities are sensitive to changes in economic conditions, including real estate values, delinquencies or defaults, or both, and may be adversely affected by shifts in the market's perception of the issuers and changes in interest rates.

19. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Investments in securities traded in active markets are measured based on unadjusted quoted prices, which represent Level 1 inputs. Investments based on Level 2 inputs include direct investments in corporate debt and other fixed-income securities. Investments included as Level 3 inputs are not observable from objective sources.

The fair value of the Company's pension plan assets by asset class and input level within the fair-value hierarchy were as follows:

millions

December 31, 2017	Level 1	Level 2	Level 3 (3)	Total
Investments				
Cash and cash equivalents	**$ 1**	**$ —**	**$ —**	**$ 1**
Fixed income	**55**	**31**	**—**	**86**
Equity securities	**185**	**—**	**—**	**185**
Other				
Real estate	**—**	**—**	**13**	**13**
Other	**—**	**53**	**—**	**53**
Investments measured at net asset value (1)	**—**	**—**	**—**	**1,086**
Total investments (2)	**$ 241**	**$ 84**	**$ 13**	**$ 1,424**
December 31, 2016				
Investments				
Cash and cash equivalents	$ 2	$ —	$ —	$ 2
Fixed income	59	33	—	92
Equity securities	347	—	—	347
Other				
Real estate	—	—	10	10
Other	—	28	—	28
Investments measured at net asset value (1)	—	—	—	861
Total investments (2)	$ 408	$ 61	$ 10	$ 1,340

(1) Certain investments measured at fair value using the net asset value per share (or its equivalent) have not been categorized in the fair value hierarchy. Amounts presented in this table are intended to reconcile the fair value hierarchy to the pension plan assets.

(2) Amount excludes receivables and payables, primarily related to Level 1 investments.

(3) The changes in level 3 investments of $3 million for the year ended December 31, 2017, and $(3) million for the year ended December 31, 2016, were attributable to the actual return on plan assets still held at the reporting date.

19. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Cash Contributions and Expected Benefit Payments While reported benefit obligations exceed the fair value of pension and other postretirement plan assets at December 31, 2017, the Company monitors the status of its funded pension plans to ensure that plan funds are sufficient to continue paying benefits. Contributions to funded plans increase plan assets, while contributions to unfunded plans are used to fund current benefit payments.

The following summarizes the Company's contributions for 2017 and expected contributions for 2018:

millions	Expected 2018	2017
Funded pension plans	$ 114	$ 167
Unfunded pension plans	16	87
Unfunded other postretirement plans	22	22
Total	$ 152	$ 276

The following summarizes estimated benefit payments for the next 10 years, including benefit increases due to continuing employee service:

millions	Pension Benefit Payments	Other Benefit Payments
2018	$ 138	$ 22
2019	155	21
2020	154	21
2021	166	20
2022	195	20
2023-2027	938	90

Defined-Contribution Plans The Company maintains several defined-contribution benefit plans, the most significant of which is the Anadarko Employee Savings Plan (ESP). All regular employees of the Company on its U.S. payroll are eligible to participate in the ESP by making elective contributions that are matched by the Company, subject to certain limitations. The Company recognized expense related to these plans of $63 million for 2017, $64 million for 2016, and $76 million for 2015.

20. Stockholders' Equity

Common Stock The Company announced a $2.5 billion share-repurchase program in September 2017, which was expanded to $3.0 billion in February 2018. The program authorizes the repurchase of the Company's common stock in the open-market or through private transactions through the end of 2018. In October 2017, Anadarko entered into an ASR Agreement to repurchase $1.0 billion of the Company's common stock as part of the $3.0 Billion Share-Repurchase Program. Under the terms of the agreement, the Company paid $1.0 billion in cash and received an initial delivery of 15.7 million shares of the Company's common stock. The initial delivery of shares represented the minimum number of shares to be repurchased under the agreement. Upon completion of the transaction in December 2017, the Company received an additional 5.1 million shares as determined by the volume-weighted average price of the shares during the term less a negotiated settlement price adjustment. During the fourth quarter of 2017, the Company repurchased an additional 1.1 million shares for $59 million through open-market purchases. At December 31, 2017, the Company had repurchased 21.9 million shares for approximately $1.1 billion (average price of $48.33 per share) under an ASR Agreement and through open-market purchases. These transactions were accounted for as equity transactions, with all of the repurchased shares classified as treasury stock. Additionally, the receipt of these shares reduced the average number of shares of common stock outstanding used to compute both basic and diluted earnings per share (EPS).

In February 2018, Anadarko completed a repurchase of 8.5 million shares for $500 million (average price of $58.82 per share) under an additional ASR Agreement.

In September 2016, the Company completed a public offering of 40.5 million shares of its common stock at a price of $53.23 per share. Net proceeds of $2.16 billion from this equity issuance were primarily used to fund the GOM Acquisition, with the remainder used for general corporate purposes. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale*. The following summarizes the changes in the Company's outstanding shares of common stock:

millions	**2017**	2016	2015
Shares of common stock issued			
Shares at January 1	**572**	528	526
Exercise of stock options	**—**	1	1
Issuance of common stock	**—**	41	—
Issuance of restricted stock	**2**	2	1
Shares at December 31	**574**	572	528
Shares of common stock held in treasury			
Shares at January 1	**21**	20	19
Purchase of treasury stock	**22**	—	—
Shares received for restricted stock vested and stock options exercised	**—**	1	1
Shares at December 31	**43**	21	20
Shares of common stock outstanding at December 31	**531**	551	508

20. Stockholders' Equity (Continued)

Earnings Per Share The Company's basic EPS is computed based on the average number of shares of common stock outstanding for the period and includes the effect of any participating securities and TEUs as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, TEUs, and WES Series A Preferred units, if the inclusion of these items is dilutive.

The following provides a reconciliation between basic and diluted EPS attributable to common stockholders for the years ended December 31:

millions except per-share amounts	**2017**	2016	2015
Net income (loss)			
Net income (loss) attributable to common stockholders	**$ (456)**	$ (3,071)	$ (6,692)
Income (loss) effect of TEUs	**(7)**	(6)	—
Less distributions on participating securities	**1**	1	3
Basic	**$ (464)**	$ (3,078)	$ (6,695)
Income (loss) effect of TEUs	**(2)**	(1)	—
Diluted	**$ (466)**	$ (3,079)	$ (6,695)
Shares			
Average number of common shares outstanding—basic	**548**	522	508
Average number of common shares outstanding—diluted	**548**	522	508
Excluded due to anti-dilutive effect	**11**	11	11
Net income (loss) per common share			
Basic	**$ (0.85)**	$ (5.90)	$ (13.18)
Diluted	**$ (0.85)**	$ (5.90)	$ (13.18)

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21. Accumulated Other Comprehensive Income (Loss)

The following summarizes the after-tax changes in the balances of accumulated other comprehensive income (loss):

millions	Interest-rate Derivatives Previously Subject to Hedge Accounting	Pension and Other Postretirement Plans	Total
Balance at December 31, 2014	$ (48)	$ (469)	$ (517)
Other comprehensive income (loss), before reclassifications	—	87	87
Reclassifications to Consolidated Statement of Income	6	41	47
Net other comprehensive income (loss)	6	128	134
Balance at December 31, 2015	$ (42)	$ (341)	$ (383)
Other comprehensive income (loss), before reclassifications	—	(107)	(107)
Reclassifications to Consolidated Statement of Income	5	94	99
Net other comprehensive income (loss)	5	(13)	(8)
Balance at December 31, 2016	$ (37)	$ (354)	$ (391)
Other comprehensive income (loss), before reclassifications	—	**(10)**	**(10)**
Reclassifications to Consolidated Statement of Income	**2**	**61**	**63**
Net other comprehensive income (loss)	**2**	**51**	**53**
Balance at December 31, 2017	**$ (35)**	**$ (303)**	**$ (338)**

22. Share-Based Compensation

At December 31, 2017, 27 million shares of the 42 million shares of Anadarko common stock authorized for awards under active share-based compensation plans remained available for future issuance. The Company generally issues new shares to satisfy awards under employee share-based payment plans. The number of shares available is reduced by awards granted. The following summarizes share-based compensation expense for the years ended December 31:

millions	**2017**	2016	2015
Restricted stock [1]	**$ 145**	$ 175	$ 157
Stock options [1]	**17**	20	19
Other equity-classified awards	**1**	2	1
Value creation plan	**—**	—	(4)
Performance-based unit awards [1]	**(13)**	38	(1)
Pretax share-based compensation expense	**$ 150**	$ 235	$ 172
Income tax benefit	**$ 35**	$ 86	$ 64

[1] Includes restructuring charges of $(7) million for performance-based unit awards in 2017 and $31 million for restricted stock, $1 million for stock options, and $7 million for performance-based unit awards in 2016. See *Note 18—Restructuring Charges* for further discussion.

22. Share-Based Compensation (Continued)

Equity-Classified Awards

Restricted Stock Certain employees may be granted restricted stock in the form of restricted stock awards or restricted stock units. Restricted stock is subject to forfeiture restrictions and cannot be sold, transferred, or disposed of during the restriction period. The holders of restricted stock awards have the same rights as a stockholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. A restricted stock unit is equivalent to a restricted stock award except that unit holders do not have the right to vote. Restricted stock vests over service periods ranging from the date of grant generally up to three years and is not considered issued and outstanding for accounting purposes until vested.

Non-employee directors are granted deferred shares, which are also considered restricted stock, that are held in a grantor trust by the Company until payable. Non-employee directors may elect to receive these shares in a lump-sum payment or in annual installments.

The following summarizes the Company's restricted stock activity:

	Shares *(millions)*	Weighted-Average Grant-Date Fair Value *(per share)*
Non-vested at January 1, 2017	4.54	$ 62.74
Granted	2.60	$ 59.92
Vested	(2.21)	$ 67.02
Forfeited	(0.24)	$ 60.95
Non-vested at December 31, 2017	4.69	$ 59.24

The weighted-average grant-date fair value per share of restricted stock granted was $52.03 during 2016 and $79.40 during 2015. The total fair value of restricted shares vested was $132 million during 2017, $114 million during 2016, and $141 million during 2015, based on the market price at the vesting date. At December 31, 2017, total unrecognized compensation cost related to restricted stock of $185 million is expected to be recognized over a weighted-average remaining service period of 2.0 years.

Stock Options Certain employees may be granted nonqualified options to purchase shares of Anadarko common stock with an exercise price equal to, or greater than, the fair market value of Anadarko common stock on the date of grant. These stock options generally vest over three years from the date of grant and terminate at the earlier of the date of exercise or seven years from the date of grant.

The fair value of stock option awards is determined using the Black-Scholes option-pricing model with the following assumptions:

- *Expected life*—Based on historical exercise behavior.
- *Volatility*—Based on an average of historical volatility over the expected life of an option and the 12-month average implied volatility.
- *Risk-free interest rates*—Based on the U.S. Treasury rate over the expected life of an option.
- *Dividend yield*—Based on a 12-month average dividend yield, taking into account the Company's expected dividend policy over the expected life of an option.

22. Share-Based Compensation (Continued)

The Company used the following weighted-average assumptions to estimate the fair value of stock options granted:

	2017	2016	2015
Weighted-average grant-date fair value	**$ 14.77**	$ 15.92	$ 18.18
Assumptions			
Expected option life—years	**4.8**	4.1	4.9
Volatility	**33.6%**	38.2%	32.4%
Risk-free interest rate	**2.0%**	1.3%	1.4%
Dividend yield	**0.4%**	0.6%	1.4%

The following summarizes the Company's stock option activity:

	Shares *(millions)*	**Weighted-Average Exercise Price** *(per share)*	**Weighted-Average Remaining Contractual Term** *(years)*	**Aggregate Intrinsic Value** *(millions)*
Outstanding at January 1, 2017	6.62	$ 76.10		
Granted	1.48	$ 49.82		
Exercised [(1)]	—	$ 47.20		
Forfeited or expired	(1.53)	$ 70.71		
Outstanding at December 31, 2017	6.57	$ 71.44	3.64	$ 7.4
Vested or expected to vest at December 31, 2017	6.57	$ 71.44	3.64	$ 7.4
Exercisable at December 31, 2017	4.41	$ 79.86	2.29	$ 0.1

(1) The total intrinsic value of stock options exercised was zero during 2017, $7 million during 2016, and $23 million during 2015, based on the difference between the market price at the exercise date and the exercise price.

Cash received from stock option exercises was zero in 2017, $30 million in 2016, and $28 million in 2015, and the tax benefit from these exercises were zero in 2017, $2 million in 2016, and $8 million in 2015.

At December 31, 2017, total unrecognized compensation cost related to stock options of $30 million is expected to be recognized over a weighted-average remaining service period of 2.1 years.

22. Share-Based Compensation (Continued)

Liability-Classified Awards

Value Creation Plan As a part of its employee compensation program, the Company offered an incentive compensation program that provided non-officer employees the opportunity to earn cash bonus awards based on the Company's TSR for the year, compared to the TSR of a predetermined group of peer companies. The Company paid $134 million during 2015. The Value Creation Plan was discontinued as an active plan after 2014.

Performance-Based Unit Awards Certain officers of the Company were provided Performance Unit Award Agreements with three-year performance periods. The vesting of these units is based on comparing the Company's TSR to the TSR of a predetermined group of peer companies over the specified performance period, with the ultimate value of any vested units determined by the Company's share price at the time of payment, as each performance unit represents the value of one share of the Company's common stock. Following the end of each performance period, the value of the vested performance units, if any, is paid in cash. The Company paid $10 million related to vested performance units in 2017, $6 million in 2016, and $9 million in 2015. At December 31, 2017, the Company's liability under Performance Unit Award Agreements was $26 million, with total unrecognized compensation cost related to these awards of $40 million expected to be recognized over a weighted-average remaining performance period of 2.1 years.

23. Noncontrolling Interests

WES is a limited partnership formed by Anadarko to acquire, own, develop, and operate midstream assets. During 2016, WES issued 22 million Series A Preferred units to private investors for net proceeds of $687 million, and issued 1.3 million common units to the Company. Proceeds from these issuances were primarily used to acquire interests in Springfield Pipeline LLC from the Company. Pursuant to an agreement between WES and the holders of the Series A Preferred units, 50% of the Series A Preferred units converted into WES common units on a one-for-one basis on March 1, 2017, and the remaining Series A Preferred units converted on May 2, 2017.

WES Class C units issued to Anadarko will convert into WES common units on a one-for-one basis on the conversion date, which was extended in February 2017 from December 31, 2017, to March 1, 2020. The Class C units receive quarterly distributions in the form of additional Class C units until the March 1, 2020 conversion date unless WES elects to convert the units to common units earlier or Anadarko elects to extend the conversion date. WES distributed 886 thousand Class C units to Anadarko during 2017, 946 thousand Class C units during 2016, and 498 thousand Class C units during 2015. WES issued approximately 874 thousand common units to the public and raised net proceeds of $57 million in 2015.

WGP is a limited partnership formed by Anadarko to own interests in WES. Anadarko sold 12.5 million WGP common units to the public for net proceeds of $476 million in 2016, and 2.3 million WGP common units to the public for net proceeds of $130 million in 2015. In June 2015, Anadarko issued 9.2 million TEUs, which include an equity component that may be settled in WGP common units. For additional disclosure of the TEU effect on noncontrolling interests, see *Note 11—Tangible Equity Units*. At December 31, 2017, Anadarko's ownership interest in WGP consisted of an 81.6% limited partner interest and the entire non-economic general partner interest. The remaining 18.4% limited partner interest in WGP was owned by the public.

At December 31, 2017, WGP's ownership interest in WES consisted of a 29.8% limited partner interest, the entire 1.5% general partner interest, and all of the WES incentive distribution rights. At December 31, 2017, Anadarko also owned a 9.1% limited partner interest in WES through other subsidiaries' ownership of common and Class C units. The remaining 59.6% limited partner interest in WES was owned by the public.

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24. Variable Interest Entities

Consolidated VIEs The Company determined that the partners in WGP and WES with equity at risk lack the power, through voting rights or similar rights, to direct the activities that most significantly impact WGP's and WES's economic performance; therefore, WGP and WES are considered VIEs. Anadarko, through its ownership of the general partner interest in WGP, has the power to direct the activities that most significantly affect economic performance and the obligation to absorb losses or the right to receive benefits that could be potentially significant to WGP and WES; therefore, Anadarko is considered the primary beneficiary and consolidates WGP, WES, and all of their consolidated subsidiaries. See *Note 23—Noncontrolling Interests* for additional information on WGP and WES.

The following tables present selected financial data from the consolidated financial statements of WGP:

millions	**2017**	2016	2015
Statement of Operations Data			
Total revenues and other	**$ 2,248**	$ 1,804	$ 1,752
Operating income (loss)	**704**	705	154
Net income (loss)	**573**	597	11
Statement of Cash Flows Data			
Net cash provided by (used in) operating activities	**$ 897**	$ 913	$ 783
Net cash provided by (used in) investing activities	**(764)**	(1,106)	(500)
Net cash provided by (used in) financing activities	**(413)**	452	(250)

millions	**2017**	2016
Balance Sheet Data		
Net property, plant, and equipment	**$ 5,731**	$ 5,050
Total assets	**8,016**	7,736
Long-term debt	**3,493**	3,119
Total liabilities	**4,071**	3,625
Total equity and partners' capital	**3,945**	4,111

24. Variable Interest Entities (Continued)

Assets and Liabilities of VIEs The assets of WGP, WES, and their subsidiaries cannot be used by Anadarko for general corporate purposes and are included in and disclosed parenthetically on the Company's Consolidated Balance Sheets. The carrying amounts of liabilities related to WGP, WES, and their subsidiaries for which the creditors do not have recourse to other assets of the Company are included in and disclosed parenthetically on the Company's Consolidated Balance Sheets.

All outstanding debt for WES at December 31, 2017 and 2016, including any borrowings under the WES RCF, is recourse to WES's general partner, which in turn has been indemnified in certain circumstances by certain wholly owned subsidiaries of the Company for such liabilities. All outstanding debt for WGP at December 31, 2017 and 2016, including any borrowings under the WGP RCF, is recourse to WGP's general partner, which is a wholly owned subsidiary of the Company. See *Note 12—Debt and Interest Expense* for additional information on WGP and WES long-term debt balances.

VIE Financing WGP's sources of liquidity include borrowings under its RCF and distributions from WES. WES's sources of liquidity include cash and cash equivalents, cash flows generated from operations, interest income from a note receivable from Anadarko as discussed below, borrowings under its RCF, the issuance of additional partnership units, or debt offerings. See *Note 12—Debt and Interest Expense* and *Note 23—Noncontrolling Interests* for additional information on WGP and WES financing activity.

Financial Support Provided to VIEs Concurrent with the closing of its May 2008 IPO, WES loaned the Company \$260 million in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The related interest income for WES was \$17 million for each of the years ended December 31, 2017, 2016, and 2015. The note receivable and related interest income are eliminated in consolidation.

In March 2015, WES acquired the Company's interest in DBJV. The acquisition was financed using a deferred purchase price obligation that required a cash payment from WES to the Company due on March 31, 2020. In May 2017, WES reached an agreement with the Company to settle this obligation whereby WES made a cash payment to the Company of \$37 million, equal to the estimated net present value of the obligation at March 31, 2017.

In order to reduce WES's exposure to a majority of the commodity-price risk inherent in certain of its contracts, Anadarko has commodity price swap agreements in place with WES expiring on December 31, 2018. WES has recorded a capital contribution from Anadarko in its Consolidated Statement of Equity and Partners' Capital for the amount by which the swap price exceeds the applicable market price. WES recorded a capital contribution from Anadarko of \$59 million for the year ended December 31, 2017, \$46 million for the year ended December 31, 2016, and \$18 million for the year ended December 31, 2015.

25. Supplemental Cash Flow Information

Additions to properties and equipment as presented within Anadarko's cash flows from investing activities include cash payments for cost of properties, equipment, and facilities. The cost of properties includes the initial capitalization of drilling costs associated with all exploratory wells whether or not they were deemed to have a commercially sufficient quantity of proved reserves. For the year ended December 31, 2015, the Company's Consolidated Statement of Cash Flows included an $881 million increase in tax receivable related to the Tronox settlement included in (increase) decrease in accounts receivable, offset by an $881 million uncertain tax position included in other items, net.

The following summarizes cash paid (received) for interest and income taxes, as well as non-cash investing and financing activities, for the years ended December 31:

millions	**2017**	2016	2015
Cash paid (received)			
Interest, net of amounts capitalized [1]	**$ 906**	$ 856	$ 2,019
Income taxes, net of refunds [2]	**64**	(882)	26
Non-cash investing activities			
Fair value of properties and equipment acquired	**$ 640**	$ 3	$ 178
Asset retirement cost additions	**66**	298	273
Accruals of property, plant, and equipment	**824**	549	754
Net liabilities assumed (divested) in acquisitions and divestitures	**(158)**	723	(114)
Property insurance receivable	**—**	—	49
Acquisition receivable	**—**	(32)	—
Non-cash investing and financing activities			
Acquisition contingent consideration	**$ —**	$ 103	$ —
Capital lease obligation [3]	**(2)**	10	—
FPSO construction period obligation [3]	**—**	11	59
Deferred drilling lease liability	**14**	30	—

(1) Includes $1.2 billion of interest related to the Tronox settlement payment in 2015.

(2) Includes $881 million from a tax refund in 2016 related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback.

(3) Upon completion of the FPSO in the third quarter of 2016, the Company reported the construction period obligation as a capital lease obligation based on the fair value of the FPSO. See *Note 12—Debt and Interest Expense*.

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26. Segment Information

Anadarko has previously presented three reporting segments in its quarterly and annual filings: Oil and Gas Exploration and Production, Midstream, and Marketing. In the first half of 2017, Anadarko substantially completed a repositioning of its asset portfolio to focus on higher margin liquids production. This shift resulted in a substantial decrease in the number of U.S. operating areas. Following the portfolio repositioning, the chief operating decision maker reviews operating results for Exploration and Production and Midstream when making operating and capital allocation decisions. Accordingly, as of the second quarter of 2017, Anadarko no longer identifies marketing activities as a separate reporting segment. Also, in prior periods, the Company aggregated its two midstream operating segments, WES Midstream and Other Midstream, into one Midstream reporting segment due to similar financial and operating characteristics. While the aggregation criteria continues to be met, the Company will no longer aggregate these operating segments in order to provide additional information about its midstream operations. Accordingly, Anadarko now has three reporting segments: Exploration and Production, WES Midstream, and Other Midstream, which include their respective marketing results. The Company has reclassified prior period amounts to conform to the current period's presentation.

The Exploration and Production reporting segment is engaged in the exploration, development, production, and sale of oil, natural gas, and NGLs and in advancing its Mozambique LNG project toward FID. The WES Midstream and Other Midstream reporting segments engage in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production as well as gathering and disposal of produced water. The WES Midstream segment consists of Western Gas Partners, LP, a publicly traded limited partnership, which is a consolidated subsidiary of Anadarko. The Other Midstream segment consists of the Company's other midstream assets.

To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; interest expense; DD&A; exploration expense; gains (losses) on divestitures, net; impairments; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income (loss) attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included restructuring charges related to the workforce reduction program included in G&A, loss on early extinguishment of debt, and certain other nonoperating items included in other (income) expense, net.

The Company's definition of Adjusted EBITDAX excludes gains (losses) on divestitures, net and exploration expense as they are not indicators of operating efficiency for a given reporting period. DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income (loss) attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

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26. Segment Information (Continued)

Management believes Adjusted EBITDAX provides information useful in assessing the Company's operating and financial performance across periods. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures, such as operating income. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes for the years ended December 31:

millions	**2017**	2016	2015
Income (loss) before income taxes	**$ (1,688)**	$ (3,829)	$ (9,689)
(Gains) losses on divestitures, net	**(674)**	757	1,022
Exploration expense	**2,541**	946	2,644
DD&A	**4,279**	4,301	4,603
Impairments	**408**	227	5,075
Interest expense	**932**	890	825
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	**156**	559	235
Restructuring charges	**21**	389	—
Other operating expense	**—**	1	74
Loss on early extinguishment of debt	**2**	155	—
Certain other nonoperating items	**—**	(58)	27
Less net income (loss) attributable to noncontrolling interests	**245**	263	(120)
Consolidated Adjusted EBITDAX	**$ 5,732**	$ 4,075	$ 4,936

The Company's accounting policies for individual segments are the same as those described in the summary of significant accounting policies, with the following exception: certain intersegment commodity contracts may meet the GAAP definition of a derivative instrument, which would be accounted for at fair value under GAAP. However, Anadarko does not recognize any mark-to-market adjustments on such intersegment arrangements. Additionally, intersegment asset transfers are accounted for at historical cost basis and do not give rise to gain or loss recognition.

26. Segment Information (Continued)

Information presented below as "Other and Intersegment Eliminations" includes corporate costs, margin on sales of third-party commodity purchases, deficiency fees, results from hard-minerals royalties, net cash from settlement of commodity derivatives, and net income (loss) attributable to noncontrolling interests. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Exploration & Production	WES Midstream	Other Midstream	Other and Intersegment Eliminations	Total
2017					
Sales revenues	$ 8,946	$ 1,715	$ 187	$ 121	$ 10,969
Intersegment revenues	23	523	172	(718)	—
Other [1]	15	153	30	67	265
Total revenues and other [2]	8,984	2,391	389	(530)	11,234
Operating costs and expenses [3]	3,555	1,330	234	212	5,331
Net cash from settlement of commodity derivatives	—	—	—	(27)	(27)
Other (income) expense, net	—	—	—	(53)	(53)
Net income (loss) attributable to noncontrolling interests [1]	—	—	—	245	245
Total expenses and other	3,555	1,330	234	377	5,496
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	—	(6)	(6)
Adjusted EBITDAX	$ 5,429	$ 1,061	$ 155	$ (913)	$ 5,732
Net properties and equipment	$ 18,598	$ 5,731	$ 1,140	$ 1,982	$ 27,451
Capital expenditures	$ 3,779	$ 956	$ 458	$ 107	$ 5,300
Goodwill	$ 4,343	$ 416	$ 30	$ —	$ 4,789

(1) Presentation has been adjusted to align with the current analysis of segment performance. Net income (loss) attributable to noncontrolling interests, previously reported within the Midstream segment, is now presented within Other and Intersegment Eliminations. Other revenues, previously reported within Other and Intersegment Eliminations, is now presented within the applicable segments.

(2) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.

(3) Operating costs and expenses excludes exploration expense, DD&A, impairments, restructuring charges, and certain other operating expenses since these expenses are excluded from Adjusted EBITDAX.

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26. Segment Information (Continued)

millions	Exploration & Production	WES Midstream	Other Midstream	Other and Intersegment Eliminations	Total
2016					
Sales revenues	$ 7,146	$ 1,055	$ 146	$ 100	$ 8,447
Intersegment revenues	7	712	185	(904)	—
Other [(1)]	(5)	114	19	51	179
Total revenues and other [(2)]	7,148	1,881	350	(753)	8,626
Operating costs and expenses [(3)]	3,518	853	228	5	4,604
Net cash from settlement of commodity derivatives	—	—	—	(265)	(265)
Other (income) expense, net [(4)]	—	—	—	(43)	(43)
Net income (loss) attributable to noncontrolling interests [(1)]	—	—	—	263	263
Total expenses and other	3,518	853	228	(40)	4,559
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	—	8	8
Adjusted EBITDAX	$ 3,630	$ 1,028	$ 122	$ (705)	$ 4,075
Net properties and equipment	$ 24,251	$ 5,050	$ 885	$ 1,982	$ 32,168
Capital expenditures	$ 2,685	$ 491	$ 59	$ 79	$ 3,314
Goodwill	$ 4,550	$ 418	$ 32	$ —	$ 5,000
2015					
Sales revenues	$ 8,250	$ 958	$ 195	$ 83	$ 9,486
Intersegment revenues	10	659	172	(841)	—
Other [(1)]	40	109	16	69	234
Total revenues and other [(2)]	8,300	1,726	383	(689)	9,720
Operating costs and expenses [(3)]	3,778	818	282	233	5,111
Net cash from settlement of commodity derivatives	—	—	—	(335)	(335)
Other (income) expense, net [(4)]	—	—	—	127	127
Net income (loss) attributable to noncontrolling interests [(1)]	—	—	—	(120)	(120)
Total expenses and other	3,778	818	282	(95)	4,783
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	—	(1)	(1)
Adjusted EBITDAX	$ 4,522	$ 908	$ 101	$ (595)	$ 4,936
Net properties and equipment	$ 25,742	$ 4,859	$ 1,038	$ 2,112	$ 33,751
Capital expenditures	$ 5,029	$ 525	$ 245	$ 89	$ 5,888
Goodwill	$ 4,945	$ 388	$ 62	$ —	$ 5,395

(1) Presentation has been adjusted to align with the current analysis of segment performance. Net income (loss) attributable to noncontrolling interests, previously reported within the Midstream segment, is now presented within Other and Intersegment Eliminations. Other revenues, previously reported within Other and Intersegment Eliminations, is now presented within the applicable segments.

(2) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.

(3) Operating costs and expenses excludes exploration expense, DD&A, impairments, restructuring charges, and certain other operating expenses since these expenses are excluded from Adjusted EBITDAX.

(4) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

26. Segment Information (Continued)

The following represents Anadarko's sales revenues (based on the origin of the sales) and net properties and equipment by geographic area:

	Years Ended December 31,		
millions	**2017**	2016	2015
Sales Revenues			
United States	**$ 9,176**	$ 7,049	$ 7,819
Algeria	**1,249**	1,103	1,189
Other International	**544**	295	478
Total sales revenues	**$ 10,969**	$ 8,447	$ 9,486

	December 31,	
millions	**2017**	2016
Net Properties and Equipment		
United States	**$ 24,382**	$ 28,024
Algeria	**965**	1,117
Other International [1]	**2,104**	3,027
Total net properties and equipment	**$ 27,451**	$ 32,168

[1] Includes $413 million of capitalized costs related to the Mozambique LNG project at December 31, 2017.

Major Customers In 2017, sales to BP PLC were $1.1 billion. This amount is included in the Exploration and Production reporting segment. In 2016 and 2015, there were no sales to customers that exceeded 10% of the Company's total sales revenues.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following summarizes quarterly financial data for 2017 and 2016:

millions except per-share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Sales revenues	**$ 2,898**	**$ 2,419**	**$ 2,610**	**$ 3,042**
Gains (losses) on divestitures and other, net	**869**	**297**	**(114)**	**(113)**
Impairments	**373**	**10**	**—**	**25**
Operating income (loss)	**(110)**	**(125)**	**(775)**	**338**
Net income (loss) [1]	**(275)**	**(334)**	**(641)**	**1,039**
Net income (loss) attributable to noncontrolling interests	**43**	**81**	**58**	**63**
Net income (loss) attributable to common stockholders	**(318)**	**(415)**	**(699)**	**976**
Earnings per share				
Net income (loss) attributable to common stockholders—basic	**$ (0.58)**	**$ (0.76)**	**$ (1.27)**	**$ 1.80**
Net income (loss) attributable to common stockholders—diluted	**$ (0.58)**	**$ (0.76)**	**$ (1.27)**	**$ 1.80**
Average number common shares outstanding—basic	**551**	**552**	**553**	**537**
Average number common shares outstanding—diluted	**551**	**552**	**553**	**537**
2016				
Sales revenues	$ 1,634	$ 1,985	$ 2,251	$ 2,577
Gains (losses) on divestitures and other, net	40	(70)	(358)	(190)
Impairments	16	18	27	166
Operating income (loss)	(864)	(332)	(793)	(610)
Net income (loss)	(998)	(611)	(747)	(452)
Net income (loss) attributable to noncontrolling interests	36	81	83	63
Net income (loss) attributable to common stockholders	(1,034)	(692)	(830)	(515)
Earnings per share				
Net income (loss) attributable to common stockholders—basic	$ (2.03)	$ (1.36)	$ (1.61)	$ (0.94)
Net income (loss) attributable to common stockholders—diluted	$ (2.03)	$ (1.36)	$ (1.61)	$ (0.94)
Average number common shares outstanding—basic	509	510	517	551
Average number common shares outstanding—diluted	509	510	517	551

[1] Includes a one-time deferred tax benefit of $1.2 billion in the fourth quarter of 2017 related to the Tax Reform Legislation.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

The unaudited supplemental information on oil and gas exploration and production activities for 2017, 2016, and 2015 has been presented in accordance with FASB Accounting Standards Codification Topic 932, *Extractive Activities —Oil and Gas,* and the SEC's final rule, *Modernization of Oil and Gas Reporting*. Disclosures by geographic area include the United States and International. For 2017, the International geographic area consisted of proved reserves located in Algeria and Ghana.

Oil and Gas Reserves

The following reserves disclosures reflect estimates of proved reserves, proved developed reserves, and PUDs, net of third-party royalty interests, of oil, natural gas, and NGLs owned at each year end and changes in proved reserves during each of the last three years. Oil and NGLs volumes are presented in MMBbls and natural-gas volumes are presented in Bcf at a pressure base of 14.73 pounds per square inch. Total volumes are presented in MMBOE. For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volumes.

Reserves for international locations are calculated in accordance with the terms of governing agreements. The international reserves include estimated quantities allocated to Anadarko for recovery of costs and income taxes and Anadarko's net equity share after recovery of such costs.

The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. The results of infill drilling are treated as positive revisions due to increases to expected recovery. Other revisions are due to changes in, among other things, development plans, reservoir performance, commodity prices, economic conditions, and governmental restrictions.

The prices below were used to compute the information presented in the following tables and are adjusted only for fixed and determinable amounts under provisions in existing contracts:

	Oil per Bbl	Natural Gas per MMBtu	NGLs per Bbl
December 31, 2017	$ 51.34	$ 2.98	$ 31.83
December 31, 2016	$ 42.75	$ 2.48	$ 19.74
December 31, 2015	$ 50.28	$ 2.59	$ 19.47

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Reserves (Continued)

	Oil (MMBbls)			Natural Gas (Bcf)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2014	704	225	929	8,668	31	8,699
Revisions of prior estimates	2	(6)	(4)	(888)	4	(884)
Extensions, discoveries, and other additions	15	—	15	60	—	60
Purchases in place	—	—	—	8	—	8
Sales in place	(111)	—	(111)	(1,003)	—	(1,003)
Production	(85)	(31)	(116)	(854)	(5)	(859)
December 31, 2015	525	188	713	5,991	30	6,021
Revisions of prior estimates	11	3	14	310	—	310
Extensions, discoveries, and other additions	24	—	24	59	—	59
Purchases in place	81	—	81	68	—	68
Sales in place	(14)	—	(14)	(1,263)	—	(1,263)
Production	(86)	(30)	(116)	(766)	(5)	(771)
December 31, 2016	**541**	**161**	**702**	**4,399**	**25**	**4,424**
Revisions of prior estimates	**47**	**23**	**70**	**644**	**12**	**656**
Extensions, discoveries, and other additions	**72**	**5**	**77**	**119**	**6**	**125**
Purchases in place	**1**	**—**	**1**	**6**	**—**	**6**
Sales in place	**(63)**	**—**	**(63)**	**(1,514)**	**—**	**(1,514)**
Production	**(97)**	**(32)**	**(129)**	**(461)**	**(6)**	**(467)**
December 31, 2017	**501**	**157**	**658**	**3,193**	**37**	**3,230**
Proved Developed Reserves						
December 31, 2014	352	190	542	6,635	27	6,662
December 31, 2015	332	159	491	5,184	30	5,214
December 31, 2016	360	147	507	3,637	25	3,662
December 31, 2017	**361**	**136**	**497**	**2,640**	**24**	**2,664**
Proved Undeveloped Reserves						
December 31, 2014	352	35	387	2,033	4	2,037
December 31, 2015	193	29	222	807	—	807
December 31, 2016	181	14	195	762	—	762
December 31, 2017	**140**	**21**	**161**	**553**	**13**	**566**

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Reserves (Continued)

	NGLs (MMBbls)			Total (MMBOE)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2014	466	13	479	2,615	243	2,858
Revisions of prior estimates [1]	(99)	4	(95)	(245)	(1)	(246)
Extensions, discoveries, and other additions	4	—	4	29	—	29
Purchases in place	—	—	—	1	—	1
Sales in place	(1)	—	(1)	(279)	—	(279)
Production	(45)	(2)	(47)	(272)	(34)	(306)
December 31, 2015	325	15	340	1,849	208	2,057
Revisions of prior estimates [1]	45	2	47	108	5	113
Extensions, discoveries, and other additions	6	—	6	40	—	40
Purchases in place	5	—	5	97	—	97
Sales in place	(69)	—	(69)	(294)	—	(294)
Production	(44)	(2)	(46)	(258)	(33)	(291)
December 31, 2016	**268**	**15**	**283**	**1,542**	**180**	**1,722**
Revisions of prior estimates [1]	**45**	**(2)**	**43**	**199**	**23**	**222**
Extensions, discoveries, and other additions	**16**	**—**	**16**	**108**	**6**	**114**
Purchases in place	**1**	**—**	**1**	**3**	**—**	**3**
Sales in place	**(64)**	**—**	**(64)**	**(379)**	**—**	**(379)**
Production	**(34)**	**(2)**	**(36)**	**(208)**	**(35)**	**(243)**
December 31, 2017	**232**	**11**	**243**	**1,265**	**174**	**1,439**
Proved Developed Reserves						
December 31, 2014	304	13	317	1,762	207	1,969
December 31, 2015	257	15	272	1,453	179	1,632
December 31, 2016	193	15	208	1,159	166	1,325
December 31, 2017	**176**	**10**	**186**	**977**	**150**	**1,127**
Proved Undeveloped Reserves						
December 31, 2014	162	—	162	853	36	889
December 31, 2015	68	—	68	396	29	425
December 31, 2016	75	—	75	383	14	397
December 31, 2017	**56**	**1**	**57**	**288**	**24**	**312**

(1) Revisions of prior estimates include the effects of new infill drilling, changes in commodity prices, and other updates, including changes in economic conditions, changes in reservoir performance, and changes to development plans. Additions generated by Anadarko's infill drilling programs were 71 MMBOE for 2017, 69 MMBOE for 2016, and 89 MMBOE for 2015.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Total proved reserves decreased by 283 MMBOE in 2017 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised upward by 222 MMBOE.

MMBOE	**December 31, 2017**
Revisions due to changes in year-end prices (price impact to opening balance)	92
Other revisions of prior estimates	
Revisions due to performance	60
Revisions due to cost updates	(4)
Revisions due to successful infill drilling	71
Revisions due to development plan updates	5
Other revisions	(2)
Total other revisions of prior estimates	130
Revisions of prior estimates	222

Positive revisions of 92 MMBOE were due to the improvement in commodity prices. The positive price-related revisions supplemented a net increase of 130 MMBOE primarily associated with the following:

- *Performance* The Company experienced an overall increase of 60 MMBOE in proved reserves due to performance improvements. Numerous areas of the Company contributed to a total upward revision of 91 MMBOE with the largest increases occurring in the DJ and Delaware basin areas. Downward revisions of 31 MMBOE were primarily due to performance reductions in the Lucius area in the Gulf of Mexico and in the Greater Natural Buttes area of the Rockies.
- *Cost updates* Annual updates reflected cost increases in certain U.S. onshore areas resulting in a minor reduction in proved reserves.
- *Infill-drilling activities* The Company added 71 MMBOE of proved reserves associated with infill drilling activities, of which 53 MMBOE was in the DJ basin, 13 MMBOE in the Lucius and Holstein areas in the Gulf of Mexico, and the remaining in the Ghana Jubilee field.
- *Development plan updates* The majority of revisions associated with updates to development plans occurred in the DJ basin due to ongoing optimization of development activity.

Extensions, discoveries, and other additions Proved reserves increased by 114 MMBOE primarily through the extension of proved acreage. Approximately 89 MMBOE was associated with drilling activities in the Delaware basin, 10 MMBOE in the Horn Mountain area in the Gulf of Mexico, and 6 MMBOE in the Ghana Jubilee Field. The remaining 9 MMBOE was associated with various other U.S. areas.

Sales in place Proved reserves decreased by 379 MMBOE due to the divestiture of certain U.S. onshore properties. The decrease was comprised of 300 MMBOE of proved developed reserves and 79 MMBOE of PUDs.

ANADARKO PETROLEUM CORPORATION
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Total proved reserves decreased by 335 MMBOE in 2016 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised upward by 113 MMBOE.

MMBOE	December 31, 2016
Revisions due to changes in year-end prices (price impact to opening balance)	(147)
Other revisions of prior estimates	
Revisions due to performance	74
Revisions due to cost reductions	100
Revisions due to successful infill drilling	69
Revisions due to development plan updates	(3)
Other revisions	20
Total other revisions of prior estimates	260
Revisions of prior estimates	113

Negative revisions of 147 MMBOE were due to the decline in commodity prices. The negative price-related revisions were offset by a net increase of 260 MMBOE associated with the following:

- *Performance* The Company experienced an overall increase of 74 MMBOE in proved reserves. Upward revisions of 102 MMBOE were primarily due to improved well performance in the DJ basin, certain U.S. shale plays, and select wells in the Gulf of Mexico. Downward revisions of 28 MMBOE were primarily due to performance updates associated with select wells in the Gulf of Mexico.
- *Cost reductions* Ongoing cost-optimization efforts and a reduced cost structure associated with the lower commodity-price environment resulted in an increase in proved reserves. The Eagleford and the DJ basin areas experienced an increase of 94 MMBOE of proved reserves associated with certain wells, included in the negative price-related revisions, which experienced restored economic producibility upon reduction of the cost structure. The remaining increase in proved reserves due to the improved cost structure is attributable to numerous areas across the Company.
- *Infill-drilling activities* The Company added 69 MMBOE of proved reserves associated with infill drilling activities, the majority of which were in the DJ basin and the K2 and Caesar/Tonga areas of the Gulf of Mexico.
- *Other revisions* Other revisions resulted from the Company's multi-step reserves reconciliation process and the elimination of duplicative adjustments to the opening reserves balance.

Extensions, discoveries, and other additions Proved reserves increased by 40 MMBOE through the extension of proved acreage, primarily as a result of successful drilling in the Delaware basin. Although shale plays represented only 20% of the Company's total proved reserves at December 31, 2016, growth in the shale plays contributed a majority of the total extensions and discoveries.

Purchases in place Proved reserves increased by 97 MMBOE due to the GOM Acquisition. The increase was comprised of 67 MMBOE of proved developed reserves and 30 MMBOE of PUDs.

Sales in place Proved reserves decreased by 294 MMBOE due to the divestiture of certain U.S. onshore properties. The decrease was comprised of 279 MMBOE of proved developed reserves and 15 MMBOE of PUDs.

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Total proved reserves decreased by 801 MMBOE in 2015 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised downward by 246 MMBOE.

MMBOE	**December 31, 2015**
Revisions due to changes in year-end prices (price impact to opening balance)	(624)
Other revisions of prior estimates	
Revisions due to performance	222
Revisions due to cost reductions	139
Revisions due to successful infill drilling	89
Revisions due to development plan updates	(126)
Other revisions	54
Total other revisions of prior estimates	378
Revisions of prior estimates	(246)

Negative revisions of 624 MMBOE were due to the decline in commodity prices and include a reduction to NGLs reserves of 43 MMBOE associated with price-induced ethane rejection. The negative price-related revisions were partially offset by a net increase of 378 MMBOE associated with the following:

- *Performance* The Company experienced an increase of 169 MMBOE in proved reserves primarily due to increases to planned lateral lengths in the Eagleford area of South Texas combined with improved well performance in the Eagleford area, the DJ basin, and the Marcellus area of the Appalachian basin. All other performance increases were a result of minor improvements from numerous areas throughout the Company.
- *Cost reductions* Capital spent in 2015 associated with ongoing drilling and completion activities, ongoing cost-optimization efforts, and a reduced cost structure associated with the lower commodity-price environment resulted in an increase in proved reserves. The DJ basin and Greater Natural Buttes areas and the Eagleford area experienced an increase of 81 MMBOE of proved reserves due to drilling activity associated with certain wells, included in the negative price-related revisions, which experienced restored economic producibility upon reduction of the capital cost structure. An increase of 14 MMBOE in proved reserves was associated with the Marcellus area where certain wells, included in the negative price-related revisions, experienced extended economic limits as a result of reductions to operating expenses during 2015. The remaining increase in proved reserves due to the improved cost structure was attributable to numerous areas across the Company.
- *Infill-drilling activities* The Company added 89 MMBOE of proved reserves associated with infill drilling activities during 2015, the majority of which were in the DJ basin.
- *Development plan updates* The majority of revisions associated with updates to development plans occurred in the DJ basin due to a significantly reduced development pace related to the decrease in commodity prices.
- *Other revisions* Other revisions resulted from the Company's multi-step reserves reconciliation process and the elimination of duplicative adjustments to the opening reserves balance.

Extensions, discoveries, and other additions Proved reserves increased by 29 MMBOE through the extension of proved acreage, primarily as a result of successful drilling in the Delaware basin. Although shale plays represented only 20% of the Company's total proved reserves at December 31, 2015, growth in the shale plays contributed almost all of the total extensions and discoveries.

Sales in place Proved developed reserves decreased by 238 MMBOE primarily associated with the divestiture of a portion of the Company's East Texas assets and EOR and CBM assets. PUDs decreased by 41 MMBOE primarily associated with divestiture activities in the U.S. onshore.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Capitalized Costs

Capitalized costs include the cost of properties, equipment, and facilities for oil and natural-gas producing activities. Capitalized costs for proved properties include costs for oil and natural-gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion. Capitalized costs associated with activities of the Company's WES Midstream and Other Midstream reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
December 31, 2017			
Capitalized			
Unproved properties	**$ 2,099**	**$ 284**	**$ 2,383**
Proved properties	**43,945**	**5,773**	**49,718**
	46,044	**6,057**	**52,101**
Less accumulated DD&A	**30,487**	**3,279**	**33,766**
Net capitalized costs	**$ 15,557**	**$ 2,778**	**$ 18,335**
December 31, 2016			
Capitalized			
Unproved properties	$ 3,332	$ 804	$ 4,136
Proved properties	47,476	5,752	53,228
	50,808	6,556	57,364
Less accumulated DD&A	30,675	2,655	33,330
Net capitalized costs	$ 20,133	$ 3,901	$ 24,034

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development

Amounts reported as costs incurred include both capitalized costs and costs charged to expense when incurred for oil and gas property acquisition, exploration, and development activities. Costs incurred also include new AROs established in the current year as well as increases or decreases to the AROs resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells, and construction of related production facilities. Costs associated with activities of the Company's WES Midstream and Other Midstream reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
Year Ended December 31, 2017			
Property acquisitions			
Unproved	**$ 490**	**$ 9**	**$ 499**
Proved	**(17)**	**—**	**(17)**
Exploration	**654**	**318**	**972**
Development	**2,610**	**29**	**2,639**
Total costs incurred	**$ 3,737**	**$ 356**	**$ 4,093**
Year Ended December 31, 2016			
Property acquisitions			
Unproved	$ 178	$ 9	$ 187
Proved	2,498	—	2,498
Exploration	398	433	831
Development	1,780	337	2,117
Total costs incurred	$ 4,854	$ 779	$ 5,633
Year Ended December 31, 2015			
Property acquisitions			
Unproved	$ 293	$ 1	$ 294
Proved	81	—	81
Exploration	503	609	1,112
Development	3,660	606	4,266
Total costs incurred	$ 4,537	$ 1,216	$ 5,753

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Results of Operations

Results of operations for producing activities consist of all activities within the Exploration and Production reporting segment. Net revenues from production include only the revenues from the production and sale of oil, natural gas, and NGLs. Gains (losses) on property dispositions represent net gains or losses on sales of oil and gas properties. Production costs are costs to operate and maintain the Company's wells, related equipment, and supporting facilities used in oil and gas operations, including labor; well service and repair; location maintenance; power and fuel; gathering; processing; transportation; production, property, and other taxes; and production-related G&A. Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, and the costs of retaining unproved leaseholds. Income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include DD&A allowances, after giving effect to permanent differences. The federal statutory rates for the periods presented below were not adjusted by recently enacted Tax Reform Legislation. The results of operations exclude general office overhead and interest expense attributable to oil and gas activities.

millions	United States	International	Total
Year Ended December 31, 2017			
Net revenues from production			
Third-party sales	$ 5,429	$ 710	$ 6,139
Sales to consolidated affiliates	1,746	1,084	2,830
Gains (losses) on property dispositions	520	13	533
	7,695	1,807	9,502
Production costs			
Oil and gas operating	803	197	1,000
Oil and gas transportation	881	33	914
Production-related G&A	341	15	356
Production, property, and other taxes	226	290	516
	2,251	535	2,786
Exploration expenses	1,699	842	2,541
DD&A	3,260	634	3,894
Impairments related to oil and gas properties	229	—	229
Other operating expense	106	108	214
	150	(312)	(162)
Income tax expense (benefit)	55	191	246
Results of operations	$ 95	$ (503)	$ (408)

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Results of Operations (Continued)

millions	United States	International	Total
Year Ended December 31, 2016			
Net revenues from production			
Third-party sales	$ 3,884	$ 619	$ 4,503
Sales to consolidated affiliates	1,871	779	2,650
Gains (losses) on property dispositions	(855)	(6)	(861)
	4,900	1,392	6,292
Production costs			
Oil and gas operating	607	204	811
Oil and gas transportation	964	38	1,002
Production-related G&A	317	20	337
Production, property, and other taxes	189	282	471
	2,077	544	2,621
Exploration expenses	541	405	946
DD&A	3,512	395	3,907
Impairments related to oil and gas properties	55	—	55
Other operating expense	62	49	111
	(1,347)	(1)	(1,348)
Income tax expense (benefit)	(494)	155	(339)
Results of operations	$ (853)	$ (156)	$ (1,009)
Year Ended December 31, 2015			
Net revenues from production			
Third-party sales	$ 4,409	$ 673	$ 5,082
Sales to consolidated affiliates	2,184	994	3,178
Gains (losses) on property dispositions	(976)	(14)	(990)
	5,617	1,653	7,270
Production costs			
Oil and gas operating	815	199	1,014
Oil and gas transportation	1,083	34	1,117
Production-related G&A	398	11	409
Production, property, and other taxes	218	270	488
	2,514	514	3,028
Exploration expenses	1,447	1,197	2,644
DD&A	3,785	399	4,184
Impairments related to oil and gas properties	4,033	—	4,033
Other operating expense	150	—	150
	(6,312)	(457)	(6,769)
Income tax expense (benefit)	(2,332)	252	(2,080)
Results of operations	$ (3,980)	$ (709)	$ (4,689)

ANADARKO PETROLEUM CORPORATION
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(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Estimates of future net cash flows from proved reserves are computed based on the average beginning-of-the-month prices during the 12-month period for the year. Estimated future net cash flows for all periods presented are reduced by estimated future development, production, and abandonment and dismantlement costs based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development, production costs, and abandonment and dismantlement. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including the reduced rate effective for years after 2017 due to Tax Reform Legislation, to the pretax net cash flows, giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense. The 10% discount factor is prescribed by GAAP.

The present value of future net cash flows is not an estimate of the fair value of Anadarko's oil and gas properties. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves, and a discount factor more representative of the time value of money and the risks inherent in producing oil and natural gas. Significant changes in estimated reserves volumes or commodity prices could have a material effect on the Company's Consolidated Financial Statements.

millions	United States	International	Total
December 31, 2017			
Future cash inflows	**$ 38,909**	**$ 8,741**	**$ 47,650**
Future production costs	**16,947**	**3,164**	**20,111**
Future development costs	**5,512**	**679**	**6,191**
Future income tax expenses	**3,106**	**2,147**	**5,253**
Future net cash flows	**13,344**	**2,751**	**16,095**
10% annual discount for estimated timing of cash flows	**3,856**	**579**	**4,435**
Standardized measure of discounted future net cash flows	**$ 9,488**	**$ 2,172**	**$ 11,660**
December 31, 2016			
Future cash inflows	$ 33,513	$ 7,328	$ 40,841
Future production costs	16,921	3,290	20,211
Future development costs	7,292	566	7,858
Future income tax expenses	2,606	1,408	4,014
Future net cash flows	6,694	2,064	8,758
10% annual discount for estimated timing of cash flows	1,658	470	2,128
Standardized measure of discounted future net cash flows	$ 5,036	$ 1,594	$ 6,630
December 31, 2015			
Future cash inflows	$ 42,919	$ 10,392	$ 53,311
Future production costs	21,100	3,829	24,929
Future development costs	7,209	637	7,846
Future income tax expenses	4,146	2,423	6,569
Future net cash flows	10,464	3,503	13,967
10% annual discount for estimated timing of cash flows	3,372	910	4,282
Standardized measure of discounted future net cash flows	$ 7,092	$ 2,593	$ 9,685

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
2017			
Balance at January 1	**$ 5,036**	**$ 1,594**	**$ 6,630**
Sales and transfers of oil and gas produced, net of production costs	**(4,924)**	**(1,260)**	**(6,184)**
Net changes in prices and production costs	**5,116**	**1,591**	**6,707**
Changes in estimated future development costs	**184**	**(92)**	**92**
Extensions, discoveries, additions, and improved recovery, less related costs	**1,478**	**98**	**1,576**
Development costs incurred during the period	**1,304**	**6**	**1,310**
Revisions of previous quantity estimates	**2,918**	**882**	**3,800**
Purchases of minerals in place	**28**	**—**	**28**
Sales of minerals in place	**(864)**	**—**	**(864)**
Accretion of discount	**674**	**260**	**934**
Net change in income taxes	**(416)**	**(641)**	**(1,057)**
Other	**(1,046)**	**(266)**	**(1,312)**
Balance at December 31	**$ 9,488**	**$ 2,172**	**$ 11,660**
2016			
Balance at January 1	$ 7,092	$ 2,593	$ 9,685
Sales and transfers of oil and gas produced, net of production costs	(3,678)	(856)	(4,534)
Net changes in prices and production costs	(1,953)	(1,607)	(3,560)
Changes in estimated future development costs	742	(126)	616
Extensions, discoveries, additions, and improved recovery, less related costs	429	—	429
Development costs incurred during the period	1,223	203	1,426
Revisions of previous quantity estimates	1,388	320	1,708
Purchases of minerals in place	193	—	193
Sales of minerals in place	(1,277)	—	(1,277)
Accretion of discount	949	431	1,380
Net change in income taxes	690	717	1,407
Other	(762)	(81)	(843)
Balance at December 31	$ 5,036	$ 1,594	$ 6,630

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Continued)

millions	United States	International	Total
2015			
Balance at January 1	$ 24,148	$ 6,512	$ 30,660
Sales and transfers of oil and gas produced, net of production costs	(4,079)	(1,153)	(5,232)
Net changes in prices and production costs	(28,967)	(8,010)	(36,977)
Changes in estimated future development costs	4,408	221	4,629
Extensions, discoveries, additions, and improved recovery, less related costs	219	—	219
Development costs incurred during the period	2,311	379	2,690
Revisions of previous quantity estimates	(1,890)	47	(1,843)
Purchases of minerals in place	30	—	30
Sales of minerals in place	(2,262)	—	(2,262)
Accretion of discount	3,648	1,143	4,791
Net change in income taxes	9,940	3,193	13,133
Other	(414)	261	(153)
Balance at December 31	$ 7,092	$ 2,593	$ 9,685

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

None.

Item 9A. Controls and Procedures

EVALUATION AND DISCLOSURE CONTROLS AND PROCEDURES

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended. The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2017.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See *Report of Independent Registered Public Accounting Firm* under Item 8 of this Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Anadarko's internal control over financial reporting during the fourth quarter of 2017 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

See *Anadarko Board of Directors, Corporate Governance—Committees of the Board, Corporate Governance—Board of Directors,* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Definitive Proxy Statement (Proxy Statement) for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 15, 2018 (to be filed with the SEC prior to April 5, 2018), each of which is incorporated herein by reference.

See list of *Executive Officers of the Registrant* under Items 1 and 2 of this Form 10-K, which is incorporated herein by reference.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer (Code of Ethics) can be found on the Company's website located at www.anadarko.com/Responsibility/Good-Governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

Item 11. Executive Compensation

See *Corporate Governance—Board of Directors—Compensation and Benefits Committee Interlocks and Insider Participation, Corporate Governance—Board of Directors—Director Compensation, Corporate Governance—Director Compensation Table for 2017, Compensation and Benefits Committee Report on 2017 Executive Compensation, Compensation Discussion and Analysis,* and *Executive Compensation* in the Proxy Statement, each of which is incorporated herein by reference. The Compensation and Benefits Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

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

See *Security Ownership of Certain Beneficial Owners and Management* in the Proxy Statement and *Securities Authorized for Issuance under Equity Compensation Plans* under Item 5 of this Form 10-K, each of which is incorporated herein by reference.

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

See *Corporate Governance—Board of Directors* and *Transactions with Related Persons* in the Proxy Statement, each of which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

See *Independent Auditor* in the Proxy Statement, which is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a) EXHIBITS

The following documents are filed as part of this Form 10-K or incorporated by reference:

(1) The Consolidated Financial Statements of Anadarko Petroleum Corporation are listed on the Index to this Form 10-K, page 85.

(2) Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith or double asterisk (**) and are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing under File Number 1-8968 as indicated.

Exhibit Number	Description
2 (i)	Agreement and Plan of Merger dated as of June 22, 2006, among Anadarko Petroleum Corporation, APC Acquisition Sub, Inc. and Kerr-McGee Corporation, filed as Exhibit 2.2 to Form 8-K filed on June 26, 2006
3 (i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 21, 2009, filed as Exhibit 3.3 to Form 8-K filed on May 22, 2009
(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of November 14, 2017, filed as Exhibit 3.1 to Form 8-K filed on November 16, 2017
4 (i)	Trustee Indenture, dated as of September 19, 2006, Anadarko Petroleum Corporation to The Bank of New York Trust Company, N.A., filed as Exhibit 4.1 to Form 8-K filed on September 19, 2006
(ii)	Third Supplemental Indenture, dated as of June 10, 2015, between Anadarko Petroleum Corporation and The Bank of New York Mellon Trust Company, N.A., filed as Exhibit 4.2 to Form 8-K filed on June 10, 2015
(iii)	Second Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.1 to Form 8-K filed on October 6, 2006
(iv)	Ninth Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.2 to Form 8-K filed on October 6, 2006
(v)	Officers' Certificate of Anadarko Petroleum Corporation, dated March 2, 2009, establishing the 7.625% Senior Notes due 2014 and the 8.700% Senior Notes due 2019, filed as Exhibit 4.1 to Form 8-K filed on March 6, 2009
(vi)	Form of 8.700% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on March 6, 2009
(vii)	Officers' Certificate of Anadarko Petroleum Corporation, dated June 9, 2009, establishing the 5.75% Senior Notes due 2014, the 6.95% Senior Notes due 2019 and the 7.95% Senior Notes due 2039, filed as Exhibit 4.1 to Form 8-K filed on June 12, 2009
(viii)	Form of 6.95% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on June 12, 2009
(ix)	Form of 7.95% Senior Notes due 2039, filed as Exhibit 4.4 to Form 8-K filed on June 12, 2009
(x)	Officers' Certificate of Anadarko Petroleum Corporation dated March 9, 2010, establishing the 6.200% Senior Notes due 2040, filed as Exhibit 4.1 to Form 8-K filed on March 16, 2010
(xi)	Form of 6.200% Senior Notes due 2040, filed as Exhibit 4.2 to Form 8-K filed on March 16, 2010
(xii)	Officers' Certificate of Anadarko Petroleum Corporation dated August 9, 2010, establishing the 6.375% Senior Notes due 2017, filed as Exhibit 4.1 to Form 8-K filed on August 12, 2010
(xiii)	Officers' Certificate of Anadarko Petroleum Corporation dated July 7, 2014, establishing the 3.45% Senior Notes due 2024 and the 4.50% Senior Notes due 2044, filed as Exhibit 4.1 to Form 8-K filed on July 7, 2014

	Exhibit Number		Description
	4	(xiv)	Form of 3.45% Senior Notes due 2024, filed as Exhibit 4.2 to Form 8-K filed on July 7, 2014 (included in Exhibit 4.xiii)
		(xv)	Form of 4.50% Senior Notes due 2044, filed as Exhibit 4.3 to Form 8-K filed on July 7, 2014 (included in Exhibit 4.xiii)
		(xvi)	Purchase Contract Agreement, dated June 10, 2015, between Anadarko Petroleum Corporation and The Bank of New York Mellon Trust Company, N.A., filed as Exhibit 4.1 to Form 8-K filed on June 10, 2015
		(xvii)	Form of Unit (included in Exhibit 4.xvi)
		(xviii)	Form of Purchase Contract (included in Exhibit 4.xvi)
		(xix)	Form of Amortizing Note (included in Exhibit 4.ii)
		(xx)	Officers' Certificate of Anadarko Petroleum Corporation dated March 17, 2016, establishing the 4.85% Senior Notes due 2021 and the 5.55% Senior Notes due 2026, and the 6.60% Senior Notes due 2046, filed as Exhibit 4.1 to Form 8-K filed on March 17, 2016
		(xxi)	Form of 4.85% Senior Notes due 2021, filed as Exhibit 4.2 to Form 8-K filed on March 17, 2016 (included in Exhibit 4.xx)
		(xxii)	Form of 5.55% Senior Notes due 2026, filed as Exhibit 4.3 to Form 8-K filed on March 17, 2016 (included in Exhibit 4.xx)
		(xxiii)	Form of 6.60% Senior Notes due 2046, filed as Exhibit 4.4 to Form 8-K filed on March 17, 2016 (included in Exhibit 4.xx)
†	10	(i)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998, filed as Appendix A to DEF 14A filed on March 16, 1998
†		(ii)	Form of Anadarko Petroleum Corporation 1998 Director Stock Plan Stock Option Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 17, 2005
†		(iii)	Key Employee Change of Control Contract, filed as Exhibit 10(b)(xxii) to Form 10-K for year ended December 31, 1997, filed on March 18, 1998
†		(iv)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b) to Form 10-Q for quarter ended September 30, 2000, filed on November 13, 2000
†		(v)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b)(ii) to Form 10-Q for quarter ended June 30, 2003, filed on August 11, 2003
†		(vi)	Form of Key Employee Change of Control Contract (2011), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2011, filed on July 27, 2011
†		(vii)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract (Applicable to Vice Presidents Other Than Executive Officers as of October 2013), filed as Exhibit 10(ii) to Form 10-Q for quarter ended March 31, 2015, filed on May 4, 2015
†		(viii)	Form of Anadarko Petroleum Corporation Key Employee Change of Control Contract for Executive Vice Presidents, filed as Exhibit 10(xvii) to Form 10-K for year ended December 31, 2016, filed on February 17, 2017
†		(ix)	Letter Agreement regarding Post-Retirement Benefits, dated February 16, 2004—Robert J. Allison, Jr., filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†*		(x)	Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2017)
†*		(xi)	Anadarko Retirement Restoration Plan (As Amended and Restated Effective as of January 1, 2017)
†*		(xii)	Kerr-McGee Corporation Benefits Retirement Restoration Plan (As Amended and Restated Effective January 1, 2017)
†		(xiii)	Anadarko Petroleum Corporation Estate Enhancement Program, filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999

	Exhibit Number	Description
†	10 (xiv)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives, filed as Exhibit 10(b)(xxxv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†	(xv)	Estate Enhancement Program Agreements effective November 29, 2000, filed as Exhibit 10(b)(xxxxii) to Form 10-K for year ended December 31, 2000, filed on March 15, 2001
†	(xvi)	Anadarko Petroleum Corporation Management Life Insurance Plan, restated November 1, 2002, filed as Exhibit 10(b)(xxxii) to Form 10-K for year ended December 31, 2002, filed on March 14, 2003
†	(xvii)	First Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective June 30, 2003, filed as Exhibit 10(b)(xliii) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xviii)	Second Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective January 1, 2008, filed as Exhibit 10(xxix) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010
†	(xix)	Anadarko Petroleum Corporation Officer Severance Plan, filed as Exhibit 10(b)(iv) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003
†	(xx)	Form of Termination Agreement and Release of All Claims Under Officer Severance Plan, filed as Exhibit 10.1 to Form 8-K filed on August 24, 2016
†	(xxi)	Form of Director and Officer Indemnification Agreement, filed as Exhibit 10 to Form 8-K filed on September 3, 2004
†	(xxii)	Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.1 to Form 8-K filed on May 27, 2008
†	(xxiii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 13, 2009
†	(xxiv)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2009
†	(xxv)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 13, 2009
†	(xxvi)	Anadarko Petroleum Corporation 2008 Director Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.2 to Form 8-K filed on May 27, 2008
†	(xxvii)	First Amendment to Anadarko Petroleum Corporation 2008 Director Compensation Plan, dated February 8, 2016, filed as Exhibit 10(xli) to Form 10-K for year ended December 31, 2015, filed on February 17, 2016
†	(xxviii)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.3 to Form 8-K filed on May 27, 2008
†	(xxix)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan (2013), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2013, filed on July 29, 2013
†	(xxx)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan Annual Deferred Shares (2016), filed as Exhibit 10(iii) to Form 10-Q for quarter ended March 31, 2016, filed on May 2, 2016
†	(xxxi)	Terms and Conditions of Elective Deferred Share Awards for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10(iv) to Form 10-Q for quarter ended March 31, 2016, filed on May 2, 2016
†	(xxxii)	Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2014, filed on July 29, 2014

	Exhibit Number		Description
†	10	(xxxiii)	First Amendment, dated December 17, 2013, to the Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2014, filed on July 29, 2014
†		(xxxiv)	Severance Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated February 16, 2012, filed as Exhibit 10.2 to Form 8-K filed on February 21, 2012
†		(xxxv)	Time Sharing Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated May 15, 2012, filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2012, filed on August 8, 2012
†		(xxxvi)	First Amendment to Time Sharing Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated June 2, 2015, filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2015, filed on July 28, 2015
†		(xxxvii)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, effective as of May 15, 2012, filed as Exhibit 10.1 to Form 8-K filed on May 15, 2012
†		(xxxviii)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, filed as Exhibit 10.1 to Form 8-K filed on May 16, 2016
†		(xxxix)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on May 15, 2012
†		(xl)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on May 15, 2012
†		(xli)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.4 to Form 8-K filed on May 15, 2012
†		(xlii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 9, 2012
†		(xliii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 9, 2012
†		(xliv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement (2014), filed as Exhibit 10.1 to Form 8-K filed on November 10, 2014
†		(xlv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Stock Option Award Agreement, filed as Exhibit 10(i) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†		(xlvi)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Restricted Stock Unit Award Agreement, filed as Exhibit 10(ii) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†		(xlvii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Performance Unit Award Agreement, filed as Exhibit 10(iii) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†		(xlviii)	Form of U.K. Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.5 to Form 8-K filed on May 15, 2012
†		(xlix)	Amended and Restated Performance Unit Award Agreement, effective November 5, 2012, for R. A. Walker, filed as Exhibit 10.3 to Form 8-K filed on November 9, 2012
		(l)	Settlement Agreement dated as of April 3, 2014, by and among (1) the Anadarko Litigation Trust, (2) the United States of America in its capacity as plaintiff-intervenor in the Tronox Adversary Proceeding and acting for and on behalf of certain U.S. government agencies and (3) Anadarko Petroleum Corporation, Kerr-McGee Corporation, and certain other subsidiaries, filed as Exhibit 10.1 to Form 8-K filed on April 3, 2014

	Exhibit Number		Description
	10	(li)	Credit Agreement, dated as of June 17, 2014, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., Citibank, N.A., The Royal Bank of Scotland plc, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on June 23, 2014
		(lii)	First Amendment to Credit Agreement, dated November 14, 2014, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on November 19, 2014
		(liii)	Amendment and Maturity Extension Agreement, dated December 14, 2015, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on December 18, 2015
		(liv)	Third Amendment and Maturity Extension Agreement, dated January 12, 2018, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 16, 2018
		(lv)	Form of Commercial Paper Dealer Agreement for Commercial Paper Program, filed as Exhibit 10.1 to Form 8-K filed on January 21, 2015
†		(lvi)	Anadarko Petroleum Corporation Key Employee Change of Control Contract, dated June 1, 2015, for Christopher O. Champion, filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2015, filed on July 28, 2015
		(lvii)	364-Day Revolving Credit Agreement, dated as of January 19, 2016, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd., Citibank, N.A., and Mizuho Bank, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 25, 2016
		(lviii)	First Amendment to 364-Day Revolving Credit Agreement, dated January 13, 2017, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 20, 2017
		(lix)	Second Amendment to 364-Day Revolving Credit Agreement, dated January 12, 2018, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the additional lenders party thereto, filed as Exhibit 10.2 to Form 8-K filed on January 16, 2018
†		(lx)	Retention Agreement, dated as of November 1, 2015, between Anadarko Petroleum Corporation and Mitchell W. Ingram, filed as Exhibit 10(lxxii) to Form 10-K for year ended December 31, 2016, filed on February 17, 2017
†		(lxi)	First Amendment to Retention Agreement, dated December 13, 2016, filed as Exhibit 10(lxxiii) to Form 10-K for year ended December 31, 2016, filed on February 17, 2017
*	12		Computation of Ratios of Earnings to Fixed Charges
*	21		List of Subsidiaries
*	23	(i)	Consent of KPMG LLP
*	23	(ii)	Consent of Miller and Lents, Ltd.
*	24		Power of Attorney
*	31	(i)	Rule 13a-14(a)/15d-14(a) Certification—Chief Executive Officer
*	31	(ii)	Rule 13a-14(a)/15d-14(a) Certification—Chief Financial Officer
**	32		Section 1350 Certifications
*	99		Report of Miller and Lents, Ltd.
*	101	.INS	XBRL Instance Document
*	101	.SCH	XBRL Schema Document
*	101	.CAL	XBRL Calculation Linkbase Document
*	101	.DEF	XBRL Definition Linkbase Document
*	101	.LAB	XBRL Label Linkbase Document
*	101	.PRE	XBRL Presentation Linkbase Document

† Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

The total amount of securities of the registrant authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrants and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the SEC, to furnish copies of any or all of such instruments to the SEC.

b) FINANCIAL STATEMENT SCHEDULES

Financial statement schedules have been omitted because they are not required, not applicable, or the information is included in the Company's Consolidated Financial Statements.

Item 16. Form 10-K Summary

Not applicable.

SIGNATURES

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

ANADARKO PETROLEUM CORPORATION

February 15, 2018 By: /s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial 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 February 15, 2018.

Name and Signature	Title
(i) Principal executive officer and director:	
/s/ R. A. WALKER R. A. Walker	Chairman, President and Chief Executive Officer
(ii) Principal financial officer:	
/s/ ROBERT G. GWIN Robert G. Gwin	Executive Vice President, Finance and Chief Financial Officer
(iii) Principal accounting officer:	
/s/ CHRISTOPHER O. CHAMPION Christopher O. Champion	Senior Vice President, Chief Accounting Officer and Controller
(iv) Directors:*	
ANTHONY R. CHASE DAVID E. CONSTABLE H. PAULETT EBERHART CLAIRE S. FARLEY PETER J. FLUOR JOSEPH W. GORDER JOHN R. GORDON SEAN GOURLEY MARK C. MCKINLEY ERIC D. MULLINS	

* Signed on behalf of each of these persons and on his own behalf:

By: /s/ ROBERT G. GWIN

Robert G. Gwin, Attorney-in-Fact

EXHIBIT 31(i)

CERTIFICATIONS

I, R. A. Walker, certify that:

1. I have reviewed this annual report on Form 10-K of Anadarko Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 15, 2018

/s/ R. A. WALKER

R. A. Walker
Chairman, President and Chief Executive Officer

EXHIBIT 31(ii)

CERTIFICATIONS

I, Robert G. Gwin, certify that:

1. I have reviewed this annual report on Form 10-K of Anadarko Petroleum Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 15, 2018

/s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

EXHIBIT 32

SECTION 1350 CERTIFICATION OF PERIODIC REPORT

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, R. A. Walker, Chairman, President and Chief Executive Officer of Anadarko Petroleum Corporation (Company), and Robert G. Gwin, Executive Vice President, Finance and Chief Financial Officer of the Company, certify to the best of our knowledge that:

(1) the Annual Report on Form 10-K of the Company for the period ended December 31, 2017, as filed with the Securities and Exchange Commission on the date hereof (Report), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 15, 2018

/s/ R. A. WALKER

R. A. Walker
Chairman, President and Chief Executive Officer

February 15, 2018

/s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

This certification is made solely pursuant to 18 U.S.C. Section 1350, and not for any other purpose. A signed original of this written statement required by Section 906 will be retained by Anadarko and furnished to the Securities and Exchange Commission or its staff upon request.